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Addressing Climate Change Impact on the Energy System: A Technoeconomic and Environmental Approach to Decarbonisation

Thesis submitted by

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Contributions of Others to the Thesis as a Whole

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> This manuscript was prepared as a short conference paper which was later submitted to a journal. The manuscript is part of Chapter 5.

Emodi, N. V., Chaiechi, T., & Beg, A. R. A. (2018, June). A Techno-Economic and Environmental Analysis of Queensland's Transition Towards a Low Carbon Society. In *International Conference on Sustainability in Energy and Buildings* (pp. 178-188). Springer, Cham.

> This paper was initially prepared as a conference paper and now a book chapter which has been integrated into Chapter 4.

Emodi, N. V., Chaiechi, T., & Rabiul, B. A. B. M. (2017). The Impact of Climate Change on Residential Energy Demand: A Case Study of Australia. Paper presented at the 35th United States Association for Energy Economics/International Association for Energy Economics (USAEE/IAEE) North American Conference 2017: *Riding the Energy Cycles*. Houston, Texas, 12th – 15th November 2017.

> This conference paper focused on residential energy demand but was improved upon and the analysis changed to focus on energy demand in Australia which was later published as a journal article which is adapted to Chapter 3.

Abstract

Background:

The provision of energy services is a vital component of the energy system. This is often considered emission-intensive and at same time, highly vulnerable to climate change conditions. This forms the fundamental objective of this thesis, poised to examine technoeconomic and environmental implications of policy intervention, targeted at cushioning impacts of climate change on the energy system.

Aims:

Four research queries are central to this work: (1) Review literature on impacts of CV&C on the energy system; (2) Estimate influence of seasonal climatic and socioeconomic factors on energy demand in Australia; (3) Model dynamic interactions between energy policies and climate variability and change (CV&C) impacts on the energy system in Australia and exploring the technoeconomic and environmental implications; and (4) Identify least-cost combination of electricity generation technologies and effective emissions reduction policies under climate change conditions in Australia.

Methods:

A systematic scoping review method was first applied to identify consistent pattern of CV&C impacts on the energy system, while spotting research gaps in studies that met the inclusion criteria. Databases consisting of Scopus and Web of Science were searched, and snowballing references in published studies was adopted. Data was collated and summarised to identify the characteristic features of the studies, consistent pattern of CV&C impacts, and locate research gaps to be filled by this study.

The second study applied an autoregressive distributed lag (ARDL) model to estimate temperature sensitive electricity demand in Australia. Estimates were used with projected temperatures from global climate models (GCMs) to simulate future electricity demand under climate change scenarios. The study further accounted for uncertainties in electricity demand forecasting under climate change conditions, in relation to energy efficiency improvement, renewable energy adoption and electricity price volatility. The estimates from the ARDL model and projections from GCMs were used for energy system simulation using the Long-range Energy Alternative and Planning (LEAP) system. It

considered climate induced energy demand in the residential and commercial sector, alongside linking the non-climate sensitive sector with energy supply sector. This model was vital to justifying policy options under investigation.

Further, LEAP modelling analysis was extended by identifying effective emission reduction policies considering CV&C impacts. Here, the Open Source Energy Modelling System (OSeMOSYS) was used for optimisation analysis to identify least-cost combination of electricity generation technologies and GHG emission reduction policies. Whereas, in the third and final study, cost-benefit analysis and estimation of long run marginal cost of electricity were conducted, while decomposition analysis of GHGs were analysed in the third study alone. Data used in the ARDL model included socioeconomic data which includes gross state product, as well as population and electricity prices from 1990-2016. The LEAP and OSeMOSYS model as used, was dated to 2014 as the base year, while several technological (power plant characteristics, household technologies), economic (energy prices, economic growth, carbon price) and environmental (emission factors, emission reduction target) variables were used to develop Australia's energy model.

Results:

The literature search generated 5,062 articles in which 176 studies met the inclusion criteria for the final literature review. Australian studies were scarce compared to other developed countries. Also, just few articles made attempt to examine decarbonisation under climate change. The ARDL model estimates and GCMs simulation of future electricity demand under CV&C show that Australia had an upward sloping climate-response functions, resulting to an increase in electricity demand. However, the researcher identified an annual increase in projected electricity demand for states and territory in Australia, which calls for the need to scale up RET.

The LEAP model results showed substantial impacts on energy demand, as well as impacts on power sector efficiency. Under the BAU scenario, CV&C will result in an increase in energy demand by 72 PJ and 150 PJ in the residential and commercial sectors, respectively. Induced temperature enlarges the non-climate BAU demand, which will increase threefold before 2050. Under the non-climate BAU, there is an expansion of installed capacity to 81.8 GW generating 524.6 TWh. Due to CV&C impacts, power output declines by 59 TWh and 157 TWh in Representative Concentration Pathways (RCP) 4.5 and 8.5 climate scenarios. This leads to an increase in generation costs by 10% from the base year, but a decrease in sales revenue by 8% and 21% in RCP 4.5 and RCP 8.5, respectively. The LEAP-OSeMOSYS model suggests renewables and battery storage systems as least-cost option. However, the configuration varied across Australia. Carbon tax policy was observed to be effective in reducing Australia's emission and foster huge economic benefits when compared to the current emission reduction target policy in the country. Also, renewable energy technologies increase electricity sales and decrease fuel cost better than fossil fuel dominated scenarios.

Conclusions:

Data from this study reveals that seasonal electricity demand in Australia will be influenced by warmer temperatures. Also, the study identified the possibility of winter peaking which is somewhat higher than summer peak demand in some states located in the southern regions of Australia. However, winter peaking is projected to decline by mid-century across the RCPs, while summer peak load is projected to increase, thereby, causing power companies to expand their generation capacity which may become underutilised. Owing to increase in cooling requirements up to 2050, policy uncertainties analysis recommend renewables to match an increasing future electricity demand.

The energy model indicates that ignoring the influence of CV&C may result in severe economic implications which range from increased demand, higher fuel cost, loss in revenue from decreased power output, as well as increased environmental externalities. The study concludes that policy options to reduce energy demand and GHG emissions under climate change may be expensive on the short-run, though, may likely secure long-run benefits in cost savings and emission reductions. It is envisaged that this could provide power sector management with initiatives that could be used to overcome cost ineffectiveness of short-term cost. The modelling results makes a case for renewable energy in Australia as lower demand for energy and increased electricity generation from renewable energy source presents a win-win case for Australia.

Keywords

Australia; Climate Change; Decarbonisation; Energy System; Optimisation; Simulation.

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Abbreviations and Acronyms used in the Body of this Thesis

ABS	Australian Bureau of Statistics
AC	Air conditioner
ADF	Augmented Dickey–Fuller
AEMO	Australian Energy Market Operator
ARDL	Autoregressive Distributed Lag
ARE	Advanced renewable economy
AUD	Australian dollars
BAU	Business-as-usual
BC OPT	Base Case Optimal
BC	Base Case
B-G LM	Breusch–Godfrey Lagrange multiplier
BPG LM	Breusch–Pagan–Godfrey Lagrange multiplier
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CCU	Carbon capture and use
CDD/HDD	Cooling degree days/Heating degree days
CESM1-CAM5	Community earth system model version 1, which includes the community atmospheric model version 5
CGE	Computable General Equilibrium
CMIP5	Coupled model intercomparison project phase 5
CO_2	Carbon dioxide
CO2	Emission Reduction Target
CSP	Concentrated solar power
CT	Carbon tax
CT	Carbon Tax
CUSUM	Cumulative sum of the recursive residual
CUSUMSQ	Cumulative sum of the recursive residual of squares tests
CV&C	Climate variability and change
EC	End of the 21st century
ECT	Error correction term
EPPA	Emissions Prediction and Policy Analysis

ERF	Emission Reduction Fund
EU	European Union
GCMs	General circulation models or Global Climate Models
GDP	Gross Domestic Product
GEMINI-E3	General Equilibrium Model of International-National Interactions between Economy, Energy and Environment
GEOTRANSF	A continuous non-linear hydrological model
GHG	Greenhouse gases
GSP	Gross state product
HVAC	Heating, ventilation and air conditioning system
IAM	Impact assessment models
I-NTEM	Interim Northern Territory Electricity Market
IPCC	Intergovernmental Panel on Climate Change
IRENA	International Renewable Energy Agency
IRP	Integrated resource planning
KPSS	Kwiatkowski–Phillips–Schmidt–Shin
LCE	Low-carbon economy
LEAP	Long-range Energy Alternatives Planning System
LGRE	Low-grid renewable economy
LRMC	Long-run marginal cost
MAPE	Mean Absolute Percentage Error
MARKAL	MARKet Allocation
MC	Mid-century
MIKE SHE	System Hydrological European
MLR	Multiple linear regression
MtCO2eq	Metric tons of carbon dioxide equivalent
NAM	Danish: Nedbør-Afstrømnings-Model
NC	Near-century
NC-MC	Near to mid-century
NEG	National Energy Guarantee
NEM	National Electricity Market
NEPP	National Energy Productivity Plan

NSW	New South Wales
NT	Northern Territory
NWIS	North West Interconnected System
O&M	Operation and maintenance
OCGT	Open cycle gas turbine
OSeMOSYS	Open Source Energy Modelling System
PC	Pulverised coal
PJ	Petajoule
PLASIM-ENTS	Planet-Simulator-Efficient Numerical Terrestrial Scheme
POL-	Policy simulation
POLES	The Prospective Outlook for Long-term Energy Systems
PV	Photovoltaic
QLD	Queensland
RCP	Representative Concentration Pathways
RESET	Ramsey Regression Specification Error Test
RET	Renewable Energy Targets
SA	South Australia
SR15	Special Report on 1.5^{o}C
SWAT	Soil and Water Assessment Tool
SWIS	South West Interconnected System
T&D	Transmission and distribution
TAS	Tasmania
TIAM-WORLD	TIMES Integrated Assessment Model
TOPKAPI	TOPographic Kinematic APproximation and Integration
TOPKAPI	TOPographic Kinematic APproximation and Integration
UK	United Kingdom
USA	United States of America
VIC	Victoria
WA	Western Australia
WEAP	Water Evaluation and Planning System

Chapter 1: Introduction and Background

"Climate change presents a unique challenge for economics: it is the greatest example of market failure we have ever seen." (Stern, 2007, p.1)

1.1 Introduction

Climate change presents an important implication for the global economy. Its impact stretches beyond economic infrastructure to the broader human society. Climate change induced events such as rising sea levels, weather extremes and increase in frequency of droughts and floods, pose grave threats to the energy system, which is crucial to the economy. Paradoxically, energy companies account for large contribution to global climate change, as emission from fossil fuel power plants make up to 40% of global GHG emissions. Yet energy companies will suffer most as global warming intensify. It is for this reason that mitigating greenhouse gas (GHG) emission from the energy sector will be vital in reducing the impact of climate change. However, achieving such reduction, without cutting down on the productivity of the energy sector calls for more investigation.

Over the years, several polices ranging from energy efficiency, improve building design, emission reduction and increased use/switching to renewable and sustainable energy source, have been put in place to combat climate change and improve resilience. Nonetheless, it is relatively unclear how effective these policies will be under a changing climate as it relates to technological, economic and environmental factors in future energy system. Technologically, we need to understand how changes in future demand will affect the configuration of power supply technologies, within an interconnected market as in the case of Australia.

Economically, power companies are curious on how global warming will affect their sales revenue and generation cost, as added cost are usually passed down to consumers. Further, the need to restructure the current energy policies in order to align it with international obligation for power sector decarbonisation require an understanding of the cost and benefit of the policy approach taken. From an environmental standpoint, there are possibilities of an increase in GHG emissions from the energy sector considering global warming conditions. A better understanding decarbonisation approach considering climate change is vital for a sustainable future.

The need to address this gap, calls for studies that are evidence-based. Therefore, understanding the progression of future energy system under climate change and intervention of energy policies, is the first approach towards establishing required evidence (Figure 1.1). In this thesis, Australia was selected as a case study due to (i) its complex energy system comprising of three major and two minor energy markets operating independently, (ii) state-based renewable energy policies, (iii) increasing GHG emissions from the electricity sector which is fossil fuel based and (iv) one of the most vulnerable countries to climate change.

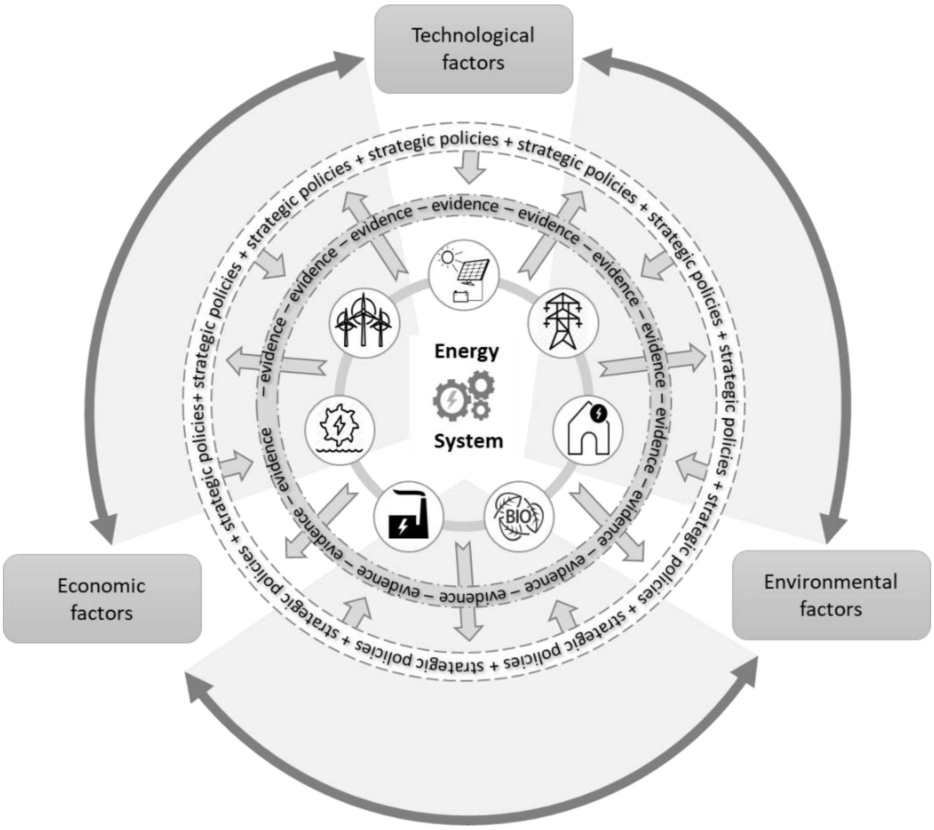

Figure 1. 1: Identifying techno-economic and environmental factors associated with climate change and exploring strategic policies based on evidence.

Australia's energy system vulnerability to climate change is validated by frequent disruptions in power supply in some states within the National Electricity Market (NEM).

Thus, the economic implication and possibility of increased emission from thermal power plants presents a situation that requires an evidence-based research to address. Sequel to foregoing, the following research questions will guide this study: (i) How will electricity demand pattern change in the future due to the influence of seasonal climatic and socioeconomic factors? (ii) What are the dynamic impacts of climate change and energy policies on future energy system? and (iii) Are emission reduction policies effective under climate change? This thesis is poised to provide answers to the questions above by:

- systematically reviewing the literature on climate variability and change (CV&C) impacts on the energy system;
- determining the seasonal pattern of energy demand influenced by climatic and socioeconomic factors;
- modelling the techno-economic and environmental pathway for the energy system considering the dynamic interaction between energy policies and CV&C impacts, and
- optimising future electricity sector to identify least-cost combination of power generation technologies and effective emission reduction policies under climate change conditions.

Following the foregoing, this thesis begins to explore pathways for energy system transition under climate change and policy scenarios to ensure sustainability and resilience of the energy system.

1.2. Background

The relationship amongst climate change, energy system and the economy are multi-directional and complex. The energy system involves complex inter-dependencies of the energy sector, which starts from energy production or resource extractions, imports and exports of energy commodities, conversion, transport or transmission, distribution and final consumption. It extends to the provision of energy services to consumers such as electricity for space heating and cooling, fuels for transportation, power plants and industrial processes, among others. It is clear that energy plays a dominant role in growth and development of the global economy (Wang et al., 2016a, Faisal et al., 2017, Yasar, 2017, Polat, 2018, Rathnayaka et al., 2018). However, increase in global population and continuous consumption of fossil fuel which is a major derivative from the energy sector reinforces global warming.

According to the United Nation Population Fund (UNPF, 1999), the world population grew from 1.6 billion to 6.1 billion in the last century, and for that duration, GHG emissions increased more than 12 times (American, 2009). It is forecasted that by 2100, the world population is expected to reach 11.2 billion (UNDESA, 2017), and global warming likely to increase by more than 2^{0}C if fossil fuel consumption is not significantly reduced (Jones and Warner, 2016).The recent Intergovernmental Panel on Climate Change (IPCC) Special Report on 1.5^{o}C (SR15) highlighted the need to limit global warming at 1.5^{o}C by drastically reducing GHG emissions by 45% in 2030, and 100% in 2050 (IPCC, 2018b). This gives the world 12 years to significantly reduce climate change consequences.

Decarbonizing the electricity sector which is the largest single source of GHG emissions (IPCC, 2015) and other energy sectors within the country and globally , is very crucial to the 2050 benchmark set by the IPCC. Further, the report suggests a complete eschew of coal-fired power plant and reducing the share of gas power plant by a third, and replacing 70-85% of the current global fuel mix with renewable energy source by mid-century (IPCC, 2018b). Global warming coupled with the increase in global population and CV&C induced energy demand, may lead to welfare setbacks for energy consumers and financial losses to power companies. Incurred welfare damages is predicated on increased expenditures on energy commodity, while financial losses are due to increase in generation cost and decrease in revenue generation as power output declines.

These damages and losses as mentioned above, are due to the vulnerability of the energy system to CV&C impacts. Energy demand, renewable and fossil fuel energy technologies are vulnerable to CV&C impacts. Renewable energy technologies such as solar photovoltaic (PV), wind and hydropower plants are may be affected by changes in temperature, solar irradiance, wind speed and precipitation. The impacts of CV&C on hydropower varies across regions as most countries in Northern Europe are projected to experience increase in precipitation due to increase in glacier melt as a result of global warming (Bonjean Stanton et al., 2016). This may force hydropower operators to expand or upgrade their facilities to accommodate the increase in water spillage (Sveinsson, 2015). Increase in air temperature can alter cell efficiencies of solar PV systems, as decrease in solar irradiance can result in lower power output (Ma et al., 2016b). Concentrated solar power (CSP) can also be affected by temperature as its solar electric generation system based on Rankine cycle (similar to most thermal power plants) can suffer from water shortage and reduction in efficiency (Schaeffer et al., 2012).

Climate change is also expected to have an impact on the availability and reliability of wind speed, which may affect the performance of wind turbines (Wohland et al., 2017, François et al., 2017). This consequence is low power generation and reduction in revenue for power plant operators. Heating and cooling requirements of thermal power plants operating under Rankine or thermodynamic and Brayton cycles and the effect may vary according to average temperature, humidity, pressure and availability of water. Coal and nuclear power plants operate under the Rankine cycle and their thermal efficiencies are affected by changes in ambient temperatures (Linrterud et al., 2011). Also, gas power plants are based on Brayton cycles (Bahrami et al., 2015), whose turbine power output and efficiency may be affected by increase in temperature and humidity. This is capable of affecting turbine performance, reduce power output, and more so, increase fuel intake (Schaeffer et al., 2012).

It is observed that electricity demand pattern can be affected by changes in temperatures, which may alter thermal comfort in buildings. Residential and commercial sectors are the most sensitive to climate change within the demand sector (Amato et al., 2005). This sensitivity is due to the cooling requirement to attain a level of thermal comfort suitable for occupants in a building. Globally, studies show that heating demand will decline, while cooling demand will increase. In some temperate regions, this will be due to warmer summer (Parkpoom and Harrison, 2008), while colder regions will have an overall decrease in energy demand due to warmer winter and reduced need for heating (Wang et al., 2010).

On the other hand, the increase in cooling demand will result in an increase in air conditioner (AC) use, which in turn will increase demand for electricity. Increase occurrence of heatwaves will result in increase in the number of households using AC for prolong periods. This will insert pressure on power networks, in terms of capacity expansion and efficiency. The consequence becomes scaling up power sector investment

(Hamlet et al., 2010). Unfortunately, power companies may have to expand their base load generation capacity which mostly depend on fossil fuel to meet the increase in demand, thereby increasing GHG emissions.

Furthermore, the vulnerability of energy system to CV&C impacts will inspire changes in economic performance of the energy sector. For example, changes in solar irradiations and surrounding temperatures can affect output for solar PV systems, and also the return on investment by extending the payback time (Ma et al., 2016b). The economic performance of hydropower systems tends to vary as increased rainfall does not imply increase in power generation and/or revenue from electricity sales (Mishra et al., 2018). However, considering annual volume changes of stream-flows, the economic performance of hydropower plants may not be affected, except when there is an experience of low rainfall during summer. This in turn reduces hydropower system ability to meet its production target before the rainfall during winter months (Payne et al., 2004, Vicuna et al., 2008, Madani et al., 2008). Besides the reduction in hydropower output due to CV&C, higher production cost may be passed down to electricity consumers. This may cause an imbalance in the supply-demand ratio which can alter sectorial consumption pattern and their activities that rely on water resources and electricity generation from hydropower station (Ospina Noreña et al., 2009, Ospina Noreña et al., 2011).

In terms of thermal power plant, operation and fuel cost present another challenge for power companies, as severe climatic conditions may result in additional operational cost (de Lucena et al., 2010). The cost will be higher if power output from other energy technologies such as wind, solar PV and hydropower systems are affected by CV&C impacts (Totschnig et al., 2017). In this situation, electricity import from interconnected energy markets may be higher, with the final consumer bearing the cost. This will result in an increase in consumers' expenditures on electricity for cooling which may not be easily offset by reduction in expenditures for heating fuels such as oil and natural gas (Clarke et al., 2018).

Also, the increase in building energy demand may indirectly increase GHG emissions if power sector is not decarbonised (Zhou et al., 2013). Emissions from buildings will differ by regions, whereas the correlation between temperature increase and GHG emissions suggests that warmer weather increases emission due to electricity demand (Scott et al., 2014, Chen et al., 2015, Spandagos and Ng, 2017). Therefore, it is important not only to examine the changes in energy mix and economic performance, but the potential increase in GHG emissions associated with CV&C impacts on the energy system.

1.3. Purpose Statement

Identifying changes in the interconnected energy sectors in relation to CV&C impacts can protect future energy system against climate change. There is need to identify impacts of CV&C across relevant sectors, in order to account for the complex inter-relationship in the energy system. Also, the increasing intensity of global warming will lead to grave economic losses for power companies and energy consumers. Therefore, the key challenge will be to identify how changes in technology, economic and environmental factors under climate change will shape future energy system. Energy policies are expected to mitigate GHG emissions. However, their interactions or effectiveness under future climate change conditions is unclear and poorly investigated (de Queiroz et al., 2019, de Lucena et al., 2010, Schlachtberger et al., 2017).

As Stern (2007) points out, investment in the next 20 years will have an effect on the climate, and decisions taken today would exercise future socioeconomic implications. Also, warnings about the climate, issued by scientists through the recently published IPCC report, further stress the need to switch the current stock of fossil fuel mix to renewable source before mid-century (IPCC, 2018b). Therefore, examining how climate change and energy policies will shape future energy system may be the key to not only mitigating GHG emissions, but cushioning CV&C impacts. Given the backdrop, this thesis examines application of a variety of policy interventions in addressing CV&C impacts on future energy system.

1.4. Research Aims

Three research questions as already presented in section 1.1 are (i) How will Australia's energy demand pattern change in the future due to the influence of seasonal climatic and socioeconomic factors? (ii) What are the dynamic impacts of climate change and energy policies on future energy system? and (iii) Are emission reduction policies effective under climate change?

This thesis presents four research aims that will begin to address the research questions by examining the seasonal changes in energy demand due to influence from climatic and socioeconomic factors. Additionally, one of the aims will explore the interaction between technoeconomic and environmental implications of energy policies and climate change. Finally, identifying effective emission mitigation policies for Australia's future energy system under climate change scenarios is another aim for the study. Clearly, the research aims are:

Research Aim #1: Review literature on impacts of CV&C on the energy system.

Research Aim #2: Estimate the influence of seasonal climatic and socioeconomic factors on electricity demand in Australia.

Research Aim #3: Model the dynamic interactions between energy policies and CV&C impacts on the energy system in Australia and exploring the technoeconomic and environmental implications.

Research Aim #4: Identify least-cost combination of electricity generation technologies and effective emissions reduction policies under climate change conditions in Australia.

The central relationships being referred to by this study are shown in Figure 1.2. The study relies heavily on these relationships to develop chapter 2 through chapter 5.

1.5 Contributions

This thesis is made up of three empirical papers and a literature review. The literature review applied a systematic scoping review approach to identify studies on CV&C impacts on the energy system. One of the three empirical papers applied an ARDL model to estimate seasonal energy demand. The second applied the LEAP model together with its extension. Available database were used to simulate the dynamic interactions between energy policies and CV&C impacts on future energy system.

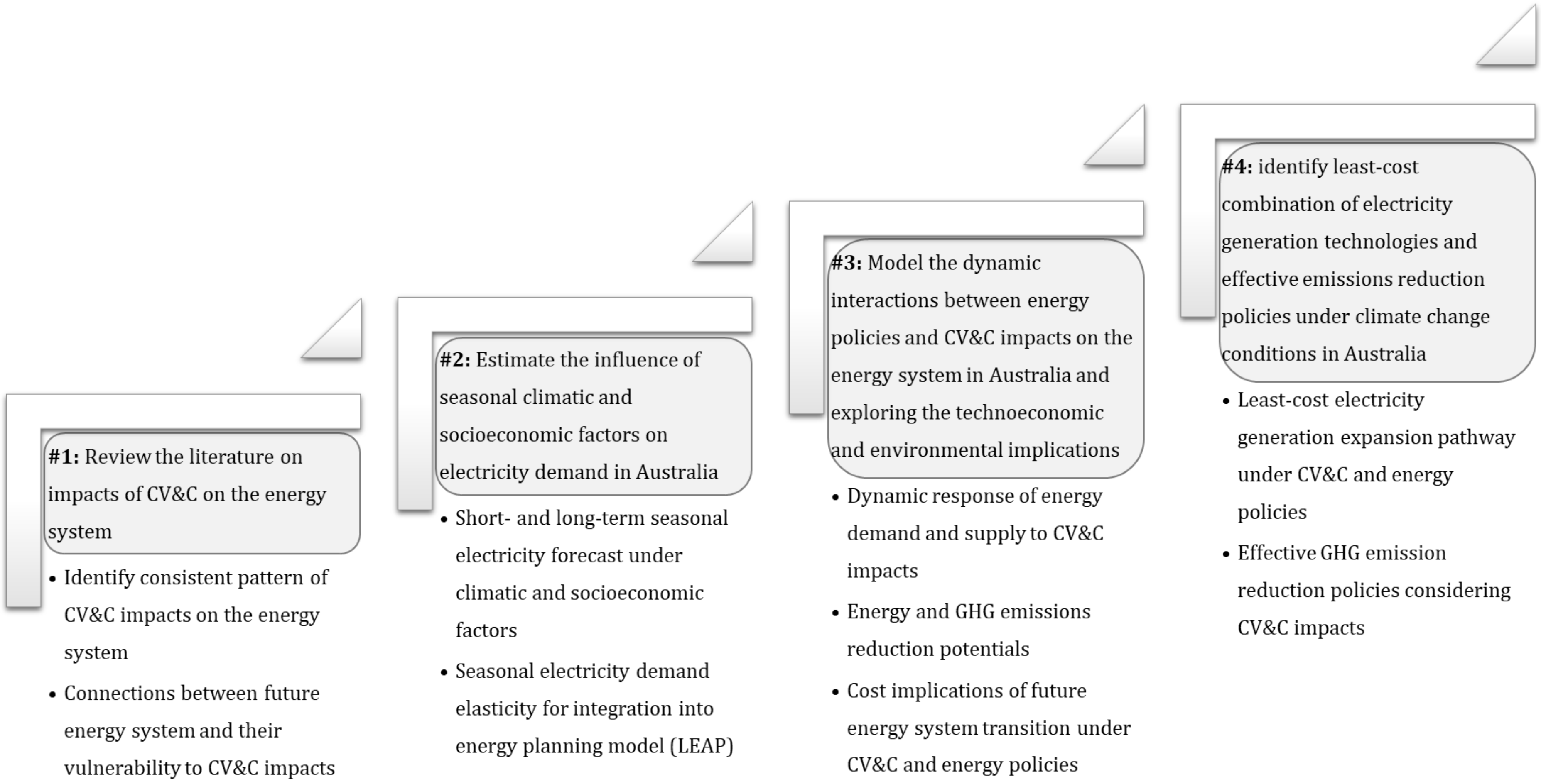

Figure 1. 2: The relationship between research aims in the thesis.

The third paper applied an optimisation model, i.e. Open Source Energy Modelling System (OSeMOSYS) which is integrated in the LEAP to identify potential GHG emission reduction policies under CV&C. It equally models the least-cost combination of electricity generation technologies for future energy system. Policies examined in this thesis include low carbon and low grid investment policies, environmental tax policies, energy efficiency, renewable energy, and emission reduction target policies. Australia is considered as a case study to examine the interactions of these policies on the country's complex energy system under CV&C impacts. Detailed contributions of the three empirical papers are presented below as sub-topics.

1.5.1. Paper 1: A Systematic Scoping Review on the Impact of Climate Variability and Change on the Energy System

This review applied a scoping review in a systematic manner following the Joanna Briggs Institute guidelines (Arksey and O'Malley, 2005, Levac et al., 2010, Peters et al., 2015). It sought to identify consistent patterns of CV&C impacts on the energy system, as well as, map and locate research gaps in literature. The paper gleaned peer reviewed articles focusing on CV&C impacts on the energy system. This review addressed the broad research question – What are the characteristics, breadth and results of existing research conducted on the impact of CV&C on the future energy system? It further makes valuable contributions to the growing body of studies by identifying consistent pattern of CV&C impacts at the global level using robust approach. It mapped several literatures to identify connections between future energy system and vulnerability to climate change.

In addition, the scoping review tracked the progress of other literature reviews, in a bid to identify gaps that have been unaddressed. This helped in deriving useful implication for future research. Nevertheless, the review found scanty literature that investigates energy sector decarbonisation under climate change. Although, it went ahead to consider socioeconomic dynamics and cross-sectoral linkages in a complete energy system model. It is important to note that scoping review has received more application in health-related fields, as compared to its scarce usage in energy disciplines. Thus, an application of this research methodology to the field of energy and climate change is a further contribution to knowledge.

1.5.2. Paper 2: The Impact of Climate Change on Electricity Demand in Australia

Following some research gaps identified in Paper 1, this study estimated the short- and long-term impact of climate change on electricity demand in Australia. More specifically, it forecasted the short- and long-term electricity demand for seven Australian states and territory, so as to determine energy consumers' response to seasonal climatic and socioeconomic factors. The ARDL model was applied to estimate temperature sensitive electricity demand which was used with projected temperatures from GCMs to simulate future electricity demand under climate change scenarios. Four climate change scenarios were examined, RCP 2.6, RCP 4.5, RCP 6.0, and RCP 8.5, and the socioeconomic variables included in the model are gross state product (GSP), population, and electricity prices. This paper argues that most studies investigating the relationship between energy consumption, weather, and socioeconomic variables have continued to ignore the importance of stationarity of the variables used in the regression models.

Also, the paper accounted for uncertainties in forecasting electricity demand under climate change conditions in relation to energy efficiency improvement, renewable energy adoption and electricity price volatility. This study finds a gradual increase in electricity consumption due to warmer temperatures with the possibility of peak demand in winter. However, demand tends to decrease in the middle of the twenty-first century across the RCPs, while the summer peak load increases by the end of the century. The non-uniform growth in seasonal electricity demand may result in an under-utilization of electricity generation capacity, thereby exerting pressure on utility providers. The implication of the underutilised capacity may have a wider economic impact on Australian NEM and Renewable Energy Targets (RETs). This study contributes to literature by presenting a model that can be useful to policymakers for effective forecast of electricity demand and accurate generation-capacity planning.

1.5.3. Paper 3: A Techno-Economic and Environmental Assessment of Long-Term Energy Policies and Climate Variability Impact on the Energy System

Some research gaps identified in Paper 1 and econometric estimates from paper 2 were incorporated in this paper. This paper examined the impact of CV&C, likewise energy policies on future energy system in Australia. Scenarios were developed to represent CV&C impacts and policy options, which were analysed with the LEAP system for the period 2010-2050. The cooling degree days (CDD) and heating degree days (HDD) elasticities and future CDD and HDD values under RCP 4.5. and RCP 8.5 climate scenarios from Paper 2 were inputted into the LEAP model by modification of its supply and demand branches. To the best of the researcher's knowledge, this study is the first to take advantage of the LEAP model in accounting for CV&C impacts on the energy system. The growth in Australia's economic sector was estimated using regression models. While future changes in electricity generation technologies followed Australian Energy Market Operator (AEMO) planning, forecasting reports, and other relevant official publications.

The study finds that CV&C will increase energy demand by 150 petajoule (PJ) by 2050 under a business-as-usual scenario. Likewise, a combined policy option of model shift and penetration of alternative vehicles can reduce transport fuel demand and GHG emissions by 49-50%. Economic analysis reveals a substantial decline in sales revenue and increase in generation costs due to CV&C impacts. Whereas, emissions and consumed energy increased under climatic conditions but decreased after policy intervention.

Given the foregoing, this study contributes to literature by comprehensively modelling the energy system, as it considers the complex socioeconomic dynamics and cross-sectoral linkages of the energy sector within an economy. Further, it makes detailed description on how the LEAP model can be used for climate change impact assessment. As such application can be extended to other energy-environmental analysis, owing to the flexibility of the LEAP modelling tool. This approach would be useful to researchers, while the overall outcome of the study can help in policy planning in Australia and other countries with similar economic structure.

1.5.4. Paper 4: Are Emission Reduction Policies Effective Under Climate Change Conditions? A Backcasting and Exploratory Scenario Approach Using the LEAP-OSeMOSYS Model

This study addresses policies for mitigating GHG emissions from the power sector and identifies least cost combinations of electricity generation technologies. Specifically, it examines the effectiveness of emission reduction policies such as emission reduction and renewable energy targets, carbon tax and national energy productivity plan (NEPP) under RCP 4.5 and RCP 8.5 climate change scenarios. The OSeMOSYS integrated within the LEAP was used for the optimisation analysis for future electricity sector of Australia. The parameters and modifications for the LEAP model from Paper 2 and 3 were applied here. Unlike Paper 3, the power sector was the focus for this paper. The long-run marginal cost of electricity for Australia future electricity market was analysed. The results identified cost optimisation scenarios as a least-cost generation pathway with less climate change impact, followed by renewable energy target and energy productivity scenarios.

Economic analysis showed that emission reduction policy will result in added cost to the economy, while carbon tax policies will yield economic benefit in installation cost, resource savings and environmental externalities reductions by 2050. The environmental analysis reveals that emission reduction policy will increase cumulative emissions, while future temperatures may double emissions from the base case scenario. Hence, this study contributes to literature by using optimisation modelling technique to identify least-cost generation pathways and effective emission reduction policies under a changing climate. It further examines the technological, economic and environmental implications of power plant expansion plan under CV&C and policy interventions. The findings can be useful in bridging the gap between power plant expansion considering climate change and cost implication of electricity sector decarbonisation.

The original contribution of this thesis is made from the simulation of policy and climate change interactions with the energy system, while considering certain socioeconomic dynamics and cross-sectoral linkages. This is a departure from previous empirical studies.

1.6. Methodology

In the literature, there are broad empirical tools used in analysing CV&C on the energy sector. Previously, econometric models and computable general equilibrium (CGE) models were the most common tools applied. However, CGE models presents some advantage over econometric models because it accounts for direct and indirect effect of climate change and emission mitigation policies. CGE models are typically market models that simulate factors of production, products, foreign exchange and equations accounting for demand and supply. The parameters in CGE models are partly calibrated and the other part is determined by econometric estimates. This makes it difficult to prove the validity of some parameters in the CGE model. Recently, tools such as Prospective Outlook on Long-term Energy Systems (POLES) (Mima and Criqui, 2015a, Dowling, 2013a) simulations model have been used for short- to mid-term impact assessment. Emphasis has been on energy demand and supply technology, as well as scenarios driven by vintage models and econometric forecast.

Other tools for energy system analysis include MARKet Allocation (MARKAL/TIMES), Model for Energy Supply Strategy Alternatives and their General Environmental Impact (MESSAGE), Hybrid Optimisation of Multiple Energy Resources (HOMER), EnergyPLAN, OSeMOSYS optimisation model and LEAP accounting model. The aim of optimisation model is to make the energy system cost effective, even as it does not wholly assess emission reduction potentials. On the other hand, accounting models such as LEAP provides a more transparent modelling that is flexible to account for technological changes, economic cost and GHG emission reduction potentials. Also, the LEAP model comes integrated with the OSeMOSYS model for power sector optimisation analysis. The flexibility of LEAP allows variables to be developed or modified within the system, though based on econometric models that can be estimated within the LEAP. Further, the LEAP model can be used to track indirect effects of energy policy changes on emission reduction in all economic sectors. The LEAP flexibility and ability makes it distinct among known modelling tools.

The distinct quality of LEAP justifies why two empirical papers discussed in this thesis applied the LEAP-OSeMOSYS modelling tool. They aimed to simulate the dynamic interactions between energy policies and CV&C impacts on the energy system, and explored the technoeconomic and environmental implications. The first empirical paper applied an ARDL model because the variables were integrated with mixed order. This can lead to spurious regression problems if stationarity of the variables are not considered. The complete methodology framework of this thesis begins from Paper 2 (i.e. chapter 3) were the estimate from the ARDL model and GCM projections was used in the LEAP model in Paper 3, and LEAP-OSeMOSYS model in Paper 4. More detailed description of the models applied in this thesis are presented in the methodology section of Paper 2 to 4.

1.7. Significance and Potential Broader Impact

Apparently, the results of this thesis can be useful in the formulation of energy and climate policies for Australia's energy system. Energy demand in Australia will increase on the long run owing to CV&C impacts, with little or no significant influence on seasonal economic or population growth. This study provides empirical data to utility operators to make better response to future demands with positive climate induced electricity supply. Also, electricity market operators in Australia can use empirical findings from this study to plan for changes in future energy system by identifying least-cost technologies for electricity generation capacity expansion.

The failed realisation of the proposed National Energy Guarantee by the Turnbull government and his successor, Scott Morrison who focused on cheaper electricity prices and the promise of reducing emissions, leaves much to be desired in terms of government meeting its own climate target of 26% below 2005 levels (AAP/SBS, 2018, staff, 2018). However, with the recent IPCC report recommending phasing out of coal power plants and reducing the share of gas plants in favour of renewables, policymakers will have to return to the drawing board to design energy policies that will ensure a resilient and sustainable future energy system for Australia. Therefore, this thesis will be of help in that regard, via providing evidence-based strategies.

Although Australia's energy system was selected as a case study in this thesis, the results can be applied in other countries with similar electricity market and energy system. All around the world, there is increasing interest in decarbonisation of the energy system, as researchers and policymakers have continued to intensify efforts in mitigating GHG emissions (ClimateWorks, 2014, Clerici et al., 2015, Bernstein and Hoffmann, 2018, Audoly et al., 2018, Craig et al., 2018, Heesterman, 2017, Li et al., 2015, Pleßmann and Blechinger, 2017, Plessmann and Blechinger, 2017, Santos-Alamillos et al., 2017). To this end, climate change may further complicate this effort, as projections already show an increase in energy demand, yet decrease in power output with increasing GHG emission under severe climatic conditions.

Sequel to the backdrop, the simulation results from this thesis can have a potential broader impact by advising policymakers in other countries on decarbonisation approach, while considering future climate change conditions. Lastly, the results from this study show technoeconomic and environmental implications of various energy policy options considering climate scenario RCP 4.5 and RCP 8.5. It is hoped that this will enable policymakers decide on the approach to take in developing future energy policy, since evidence of cost and emission reduction potentials have emerged.

1.8. Structure of the Thesis

This thesis comprises five chapters as shown in Figure 1.3. The current introductory chapter is followed by other 4 chapters based on the four papers described in section 1.5. Chapter 2 presents a review of the current literature on the impacts of CV&C on the energy system. Chapter 2 identified the state-of-the-art in the literature, while mapping the consistent pattern of CV&C impacts and establishing connections between future energy system and their climate vulnerabilities. Chapter 3 estimates the influence of seasonal climatic and socioeconomic factors on electricity demand in Australia. Chapter 3 forecasted the short- and long-run seasonal electricity demand under climatic and socioeconomic factors. The seasonal electricity demand elasticity was integrated into the energy system model used in Chapter 4 and 5.

Chapter 4 modelled the dynamic interactions between energy policies and CV&C impacts on the energy system in Australia. This includes energy demand and supply, climate impacts, energy and GHG emissions reduction policies, as well as the cost implications of future energy system transition under climate and policy scenarios. Chapter 5 identified least-cost combination of electricity generation technologies and further identified effective decarbonisation policies under climate change conditions in Australia. The modelling in Chapter 4 and 5 applied a technoeconomic and environmental assessment to decarbonisation in order to derive relevant policy implications for a resilient and sustainable future in Australia.

The four chapters are summarised with key findings in chapter 6 which also includes policy implications, relevance of the thesis and directions for future research. The methodology, discussion and policy implication of individual papers can be found in their respective sections in chapter 2 to 5 in this thesis.

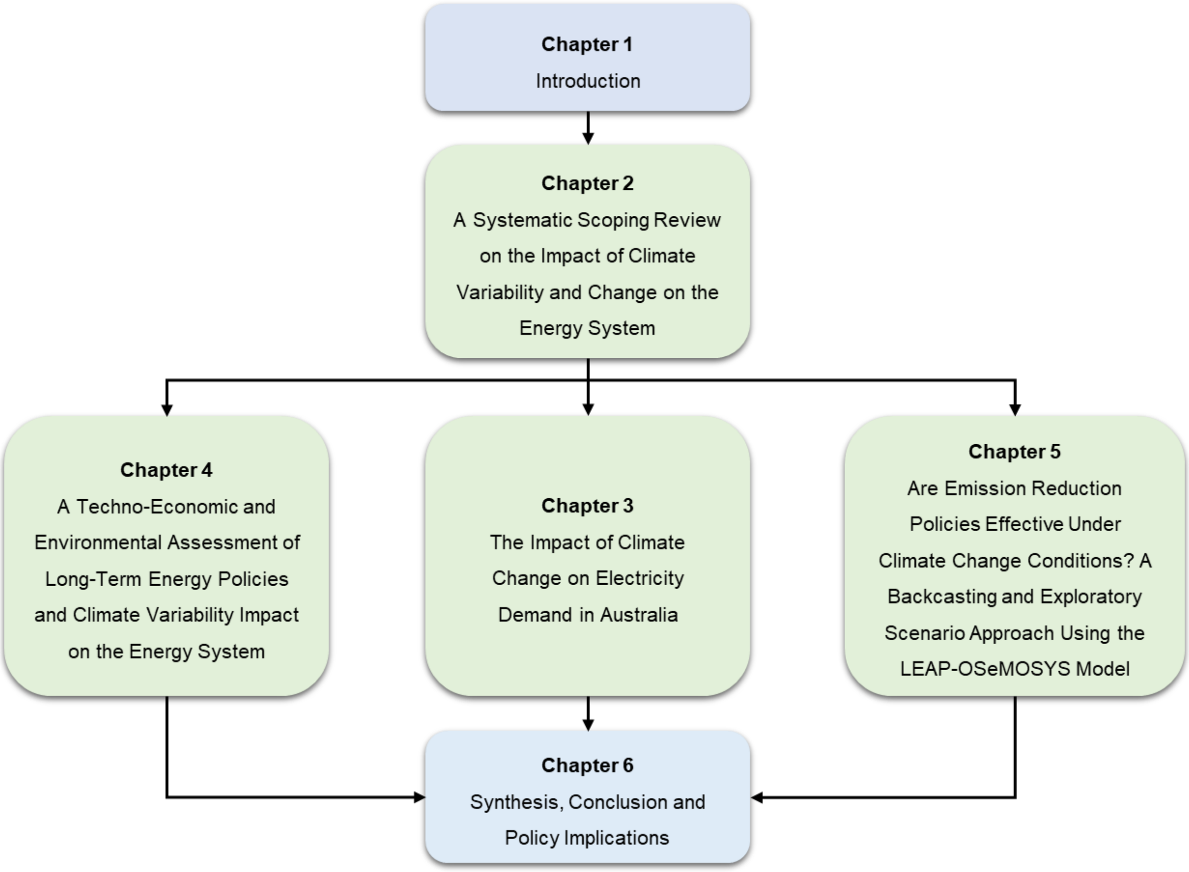

Figure 1. 3: Thesis outline.

Chapter 2: A Systematic Scoping Review on the Impact of Climate Variability and Change on the Energy System

The previous chapter introduced the thesis and gave a background view of how CV&C affects the energy system, and equally explained the research problem the thesis intends to address. Chapter 2 describes the first specific aim of this thesis – Review the literature on impacts of CV&C on the energy system (see Figure 2.1). The chapter gleans existing literature, in a bid to identify research gaps that subsequent chapters will address. Literature search was last updated in 6 April 2019 to include additional relevant articles that were identified. Some of which are cited and referenced across chapters of this thesis.

This chapter has been adapted into a manuscript: Emodi, N.V., Chaiechi, T., Beg, A.R.A. (2019). The Impact of Climate Variability and Change on the Energy System: A Systematic Scoping Review. *Science of the Total Environment*.

For this systematic scoping review, the Preferred Reporting Items for Systematic Reviews and Meta-Analyses checklist is presented in Appendix 1; scorecard and articles included for the review are presented in Appendix 2; and Appendix 3 which includes detailed results for country and regional level results can be retrieved online from: https://data.mendeley.com/datasets/tmwy4wxyj2/1. Also, Table A2.3 (summary of literature review studies) and Table A2.4 (summary of articles included for the qualitative study) which is part of Appendix 2 can be retrieved online from: https://data.mendeley.com/datasets/zy4cgky783/1.

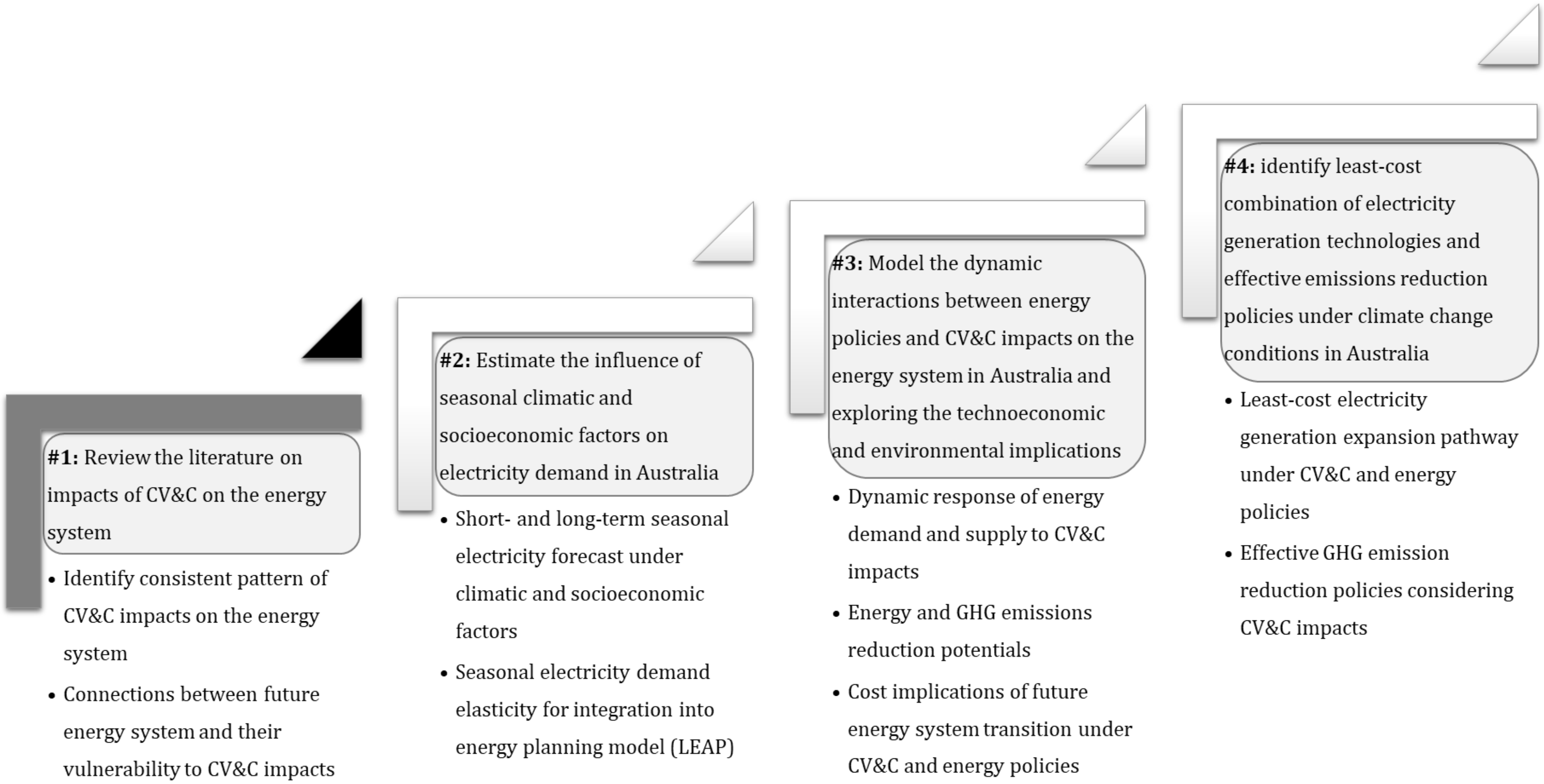

Figure 2. 1: Progress through the thesis: Specific Aim #1.

2.1. Abstract

The energy system is a vital infrastructure which can be vulnerable to climate variability and change (CV&C) impacts. Understanding the impacts can prevent disruption and inform policy decision making. This study applied a scoping review in a systematic manner following the Joanna Briggs Institute guidelines to identify consistent patterns of CV&C impacts on the energy system, map and locate research gaps in the literature. A total of 176 studies were identified as eligible for inclusion in the review. This study found evidence of consistent increase in energy demand for Africa, the Americas and Asian continent. Consistent decrease was found in Northern and Eastern Europe, while increase in residential demand was projected in Oceania. There was evidence of consistent decrease in thermal power plant output globally. Solar photovoltaic showed a robust consistent pattern of increase in the Caribbean and Central America, Northern and Southern Africa and Oceania. As the global climate is changing in a future that is highly uncertain, the energy system should also evolve in order to adapt to the changing climate. Future impact assessment must integrate the impact of CV&C on power demand and supply while consider socioeconomic dynamics, cross-sectoral linkages and back-loops in a complete energy system model.

2.2. Introduction

On October 8, 2018, the Intergovernmental Panel on Climate Change (IPCC) released a special report, Global Warming of 1.5^{o}C (IPCC, 2018b). The report highlighted the need to reduce greenhouse gases (GHGs) to net zero in the next 12 years to have a reasonable chance of limiting global warming to 1.5^{o}C. The climate scientists warn that even half degree above will significantly increase the risks of frequent and intense drought, floods, extreme heat and poverty to millions of people. The global temperature has warmed by 1^{o}C since preindustrial periods and the IPCC reports suggest cutting emissions by 45% in 2030 and 100% in 2050, to prevent the earth from warming above 1.5^{o}C (IPCC, 2018b) . This implies that 70-85% of electricity should be sourced from renewables, putting a price on GHG emission and using technologies such as carbon capture and storage (CCS) to limit the accumulation of carbon dioxide (CO_2) in the atmosphere.

Besides the IPCC report, renewable energy system has been highlighted in most studies as a solution to mitigate climate change and provide an economic means of electricity generation. Some recent studies such as Teske (2019) show that it is possible to keep the earth below the 1.5^{o}C limit by transitioning to a 100% renewable energy system, engage in a major land conservation and restoration effort by mid-century. Another study by Bogdanov et al. (2019) suggest that a 100% carbon neutral renewable-based electricity system is possible by 2050 and economically feasible with solar and wind energy as the main source of electricity of about 70% and 18%, respectively. These studies among others, consolidates the move of scientific insights towards highly renewable energy systems.

In recent times, there have been some questions arising on the application of CCS as part of the solution space on climate change mitigation. Most outdated integrated assessment models have been found to be biased and strongly push for fossil fuel CCS, which is found by real state of the art research as highly questionable. This is because all renewable energy technologies simply cost less on a higher sustainability basis and lower cost basis. Therefore, industrial CCS application can be avoided. Some CCS parts may be switched to carbon capture and use (CCU), where the captured CO_2 can potentially be used for the manufacturing of fuels, carbonates, polymers and chemicals. Some current studies (Breyer et al., 2017, Breyer et al., 2018, Creutzig et al., 2017, Jacobson et al., 2018a, Jacobson et al., 2018b, Pursiheimo et al., 2018) show that fossil CCS is a solution of the past and no longer required in real progressive energy system modelling. Besides, CCS technology doubles the cost of power production which may be passed to the final consumers (İşlegen and Reichelstein, 2011). Therefore, the sustainability of the energy system and a progressive future under climatic conditions may require a more critical position for fossil CCS in mitigating global warming.

Global warming or climate change refers to the rise in average surface temperatures on the earth surface over a long period of time. Similarly, climate variability describes the way climate elements such as temperature and precipitation deviate from its average value in given months, seasons, years, decades or even centuries (Australia, 2018a). Mitigating climate variability and change (CV&C) and its impacts will require the progressive decline of GHGs from 2030 to 2050 as suggested by the IPCC report. However, the reversal has been the case as the evolution of atmospheric CO_2 has been increasing and has reached an unprecedented high of ~410 parts per million (ppm) (CO2.Earth, 2019). Climate models such as the general circulation models (GCMs) developed in the 1950s are valuable tools for quantitative understanding of climate dynamics and forecasting of future climate change (Weart, 2010, Edwards, 2011). The GCM projections are also used to understand the impacts of CV&C on human society and infrastructure.

The energy system is an important human infrastructure which is define by the IPCC as "all components related to the production, conversion, delivery and use of energy" (Intergovernmental Panel on Climate Change, 2015). Understanding the impacts of CV&C on energy systems is increasingly important for energy consumers, energy supply companies and policymakers. This is because CV&C may affect consumers through expenditures on energy commodities, companies through higher fuel consumption and emissions, and policymakers who struggle to make policies limiting global warming and ensuring energy security. The energy system is an important infrastructure in many countries and disruption can have serious economic implications.

Several studies have examined the impacts of CV&C on the energy sector and these studies include empirical[1] based studies and literature review-based studies. Empirical based studies apply a series of impact assessment models to explore the pattern of CV&C impacts on energy demand and supply. For example, Wang et al. (2017), Rey-Hernández et al. (2018) identified patterns of CV&C impacts in buildings, while Tobin et al. (2018), Zhou et al. (2018), François et al. (2018) examined the vulnerability of energy generating technologies to CV&C impacts. Literature review-based studies surveys the literature to identify state-of-the art in CV&C impacts. For example, Yau and Pean (2011) Li et al. (2012a) Auffhammer and Mansur (2014) Ranson et al. (2014) Schaefli (2015) reviewed the literature on CV&C impacts on energy demand in buildings, Pryor and Barthelmie (2013) surveyed the literature on CV&C impacts on wind energy, Lumbroso et al. (2015) Sample et al. (2015) Schaefli (2015) Pokhrel et al. (2018) Shu et al. (2018) focused on hydropower studies, while Schaeffer et al. (2012) Chandramowli and Felder (2014)

[1] Empirical based studies are classified as original research, which differ from systematic reviews. Empirical studies described here includes studies that apply both statistical techniques such as econometric models, engineering simulation models, computable general equilibrium model, and life cycle assessment, and other related methods.

Ciscar and Dowling (2014) reviewed studies on CV&C impacts on energy demand and supply.

As empirical studies investigating CV&C impacts continues to expand, literature reviews have increased, applying methods ranging from narrative to systematic review. Systematic review approach is used to collate, evaluate and interpret results and it has been the least applied review method in the literature. Limited studies include Bonjean Stanton et al. (2016) who applied a systematic review to collate consistent patterns of impacts of CV&C on electrical supply systems in Europe, while Cronin et al. (2018) used a semi-systematic review to assess the trends of CV&C impacts on energy supply system. This study builds on Bonjean Stanton et al. (2016) and Cronin et al. (2018) but extends the studies to identify consistent pattern of CV&C impacts on the energy system at the global level. A systematic scoping review was applied to map the literature and identify consistent pattern of CV&C impacts on future energy system based on a broad range of robust evidence. By mapping the literature, this study identifies proximity and connections in terms of CV&C impacts at the regional and country-level and geographical distribution of studies and methods applied in general. Therefore, this study fits into the landscape of previous literature review on CV&C impacts of the energy system and applies a scoping review in a systematic manner.

Scoping review has been well applied in the field of health sciences. In general, the term scoping reviews means to '*map rapidly*' the key concepts underpinning a research area, main source and type of evidence available, and can be conducted as a stand-alone review, especially when a complex area has not been comprehensively reviewed (Wilson et al., 2012). A scoping review can be undertaken to systematically search, identify and map the literature. Examples of studies applying systematic scoping reviews in the health sciences includes Chambers et al. (2012), Olariu et al. (2018), Conklin et al. (2015). Besides Freiberg et al. (2018) who systematically scoped the literature to identify the health effects of people living near biomass power plants, the authors of this study are not aware of any scoping review on CV&C impacts on future energy system.

This study contributes to the growing literature by identifying consistent pattern of CV&C impacts at the global level using robust approach and mapped the literature to identify connections between future energy system and their vulnerability to climate change. The contributions of this study would be useful to advice energy companies and policymakers on planning for the future energy system considering future climate conditions. The rest of this chapter is arranged as follows. Section 2.2 describes the methods applied in the systematic scoping review. Section 2.3 presents the results of previous literature reviews, study characteristics of the current studies reviewed and patterns of CV&C impacts. The discussion is presented in Section 2.4 which includes summary of the body of evidence, implications of the review, potential mitigation and adaptation measures, gaps in the literature review and strength and limitations of the systematic scoping review. Section 2.5 concludes the study.

2.3. Methods

The methodology for this systematic scoping review is based on the Joanna Briggs Institute guidelines on conducting systematic scoping reviews (Arksey and O'Malley, 2005, Levac et al., 2010, Peters et al., 2015). The methodology summarises the evidence available on a topic in order to convey the breadth and depth of that topic (Olariu et al., 2018). The review was conducted in the following five key steps: (i) identifying the research question, (ii) identifying relevant studies, (iii) study selection, (iv) charting the data, and (v) collating, summarising and reporting the results. In this study, the scoping review is used to systematically map the literature, identify key concepts in the research, types and sources of evidence to inform policymaking and research (Wilson et al., 2012). The protocol used in this study was not registered as PROSPERO[2] currently does not accept systematic scoping review protocols and reviews that is not health related. The PRISMA[3] (Preferred Reporting Items for Systematic Reviews and Meta-Analyses) checklist for this paper is presented Appendix 1.

2.3.1. Research question

This review is guided by the question, '*What are the characteristics, breadth and results of existing research conducted on the impact of CV&C on the future energy system?*

[2] PROSPERO is an international database of prospectively registered systematic reviews in health and social care. See https://www.crd.york.ac.uk/prospero
[3] Preferred Reporting Items for Systematic Reviews and Meta-Analyses. See http://www.prisma-statement.org

2.3.2. Identification of relevant studies

The literature search aimed to systematically identify peer-reviewed literature on the evidence of CV&C impacts on the energy system. The initial search was implemented on September 3, 2018, in two electronic databases: Scopus (includes records from 1960 to date) and Web of Science (records from 1965 to date). The databases were selected to be comprehensive and cover a broad range of disciplines. The search query consists of terms considered by the authors to be relevant words related to climate variability and change, impacts and vulnerability, and energy or power. Searches were limited to English language articles published between January 1990 and December 2018. The search was limited to articles from 1990 to conform with the IPCC First Assessment Report which was published in 1990 (Houghton et al., 1990).

The search string shown in Table 2.1 was applied to Scopus and Web of Science databases which returned 4,193 and 1,892 articles, respectively. The literature search was extended to Google search engine and Google Scholar to identify peer-review articles from journals that might not be indexed in the two databases. The search returned a total of 284 articles which were added to the results from the two databases. The final search approach adopted a 'snowball' technique in which citations within articles were manually searched if they appeared relevant to the review and included in this review (Wohlin, 2014). All citations were imported into the Endnote (Reuters, 2013) reference management software which was used to manage bibliographies and references used in this review.

Table 2. 1: Search query used to retrieve articles for the review.

Query	Scopus (200-2018) TITLE-ABS-KEY	Web of Science (2000-2018) Topic
"Climat* change*" AND "impact" AND "*energy*" AND "*lectric*" AND "*power*"	1,416	603
"Climat* change*" AND "variability" AND "*energy*" AND "*lectric*" AND "*power*"	94	68
"Climat* change*" AND "?ffect*" AND "*energy*" AND "*lectric*" AND "*power*"	1,753	878
"*temperature* change" AND "impact*" AND "*energy*" AND "*lectric*" AND "*power*"	42	15
"*temperature* change" AND "?ffect*" AND "*energy*" AND "*lectric*" AND "*power*"	195	56
"*weather* conditions*" AND "?ffect*" AND "*energy*" AND "*lectric*" AND "*power*"	500	182
"*weather* conditions*" AND "*impact*" AND "*energy*" AND "*lectric*" AND "*power*"	193	90
Total	4,193	1,892

2.3.3. Study selection process

Prior to the article selection process, duplicates and irrelevant papers were removed. The authors independently reviewed and applied selection criteria to the titles and abstracts. The initial selection was broad to accommodate any literature related to CV&C impacts on energy systems. After reviewing the broad range of articles based on their titles and abstracts, the criteria were narrowed to only include studies focusing on the impacts of CV&C on energy systems in the near-, medium- and long-term (in this study, we use 'century' instead of '-term'). During the reviewing process, the references were tagged as 'literature reviews', 'out-of-study scope' and 'not available' for references that could not be retrieved as the documents were not available. The tagged references were used to store excluded studies that did not meet the eligibility criteria. Following Porter et al. (2014), Bonjean Stanton et al. (2016), a scorecard was developed to screen articles and ensure results (or projections) were suitable for inclusion in this review. The scorecard rated articles using star screening approach.

The score card contains attributes which includes the study approach, methodology, results and analysis and policy implication. The attributes of the scorecard are presented in Table A2.1 in Appendix 2. A five-star article clearly describes the study approach that is appropriate for the impact assessment with a balance description of applied methodology and results obtained, states limitations and presents policy implication. A Four-star article assumes the attributes of a five-star article but detailed information of the GCMs, results comparison with previous studies and model limitation were not included. Three-star article includes the attributes of four start article but a clear description of number of GCMs, scenarios and impact models, the use of the results for planning and implications are not presented. Articles below three stars provided little information on impact assessment methods and parameters, and results from such studies were not reliable enough to be considered for this review. Throughout the screening process, the reviewers met regularly to resolve conflicts and discuss any issue related to articles selected for this review (Levac et al., 2010).

2.3.4. Charting the data

After the study selection process, there were 176 articles scoring between three to five stars with publication dates ranging from 1992 to 2018. Figure 2.2 shows the evolution of studies included for this review and 2016 can be observed to be the year with higher number of publications. This might be due to the call for contributions by the IPCC Special Report on Global Warming 1.5°C which was made in 2017. The studies included were used to develop a charting table to record qualitative information of the authors, study location, aim, assessment method, results and limitations. The qualitative information from studies included were used to identify projected impacts of CV&C on the energy system for the future period assessed, and to examine the consistent or inconsistent nature of the results. Here, higher number of consistent results implies a more robust pattern of CV&C impacts for the energy system. The approach identified 153 studies which were used for quantitative synthesis to identify the pattern of CV&C impacts on energy demand and energy technologies (labelled #1-153 in Table A2.2 in Appendix 2). The quality (risk of bias) of three to five-star studies were independently assessed by the authors.

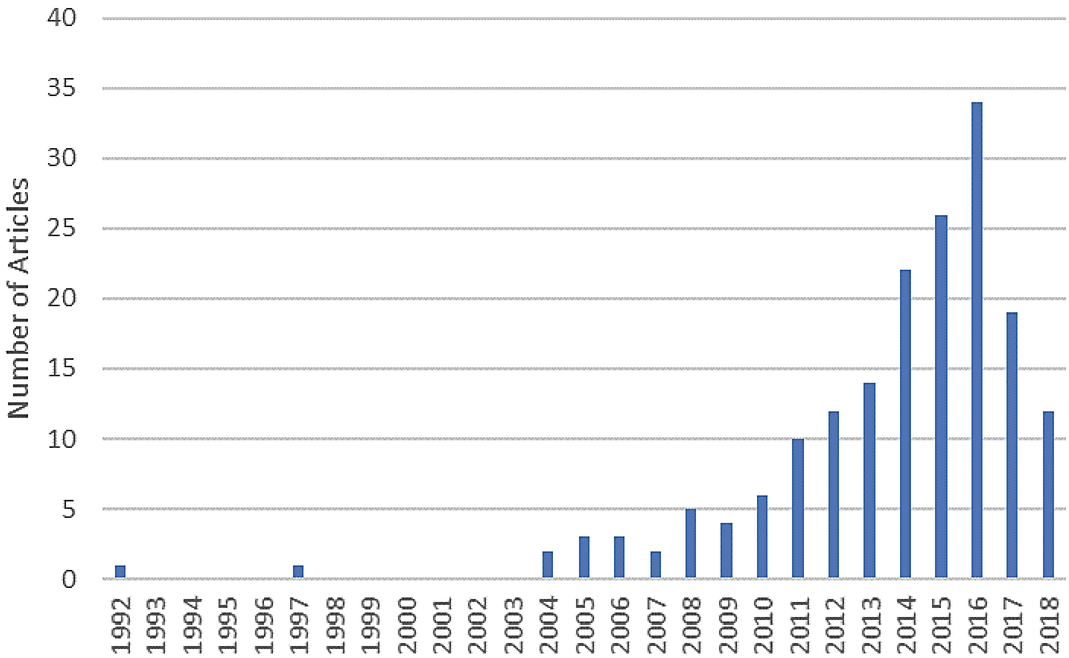

Figure 2. 2: Article included in the review by publication year.

The 153 studies produced 1,790 individual results for patterns of CV&C at regional and country level. The pattern of impacts was either increase, decrease or no change and the assessment periods were for the near (present to 2039 or 2030s), medium- (2040 to 2069, or 2050s) and end-century (2070 to 2099, or 2080s). However, the heterogeneity of the assessment periods used in the studies made it challenging to present an overall result. Therefore, the results were re-mapped into two assessment periods, near to mid-century (NC-MC) and end of the 21st century (EC). The results of the near-, mid-, and end-century are available at the country and regional level in sheet 2 and sheet 3 in Appendix 3.

In terms of the pattern of impact, an increase in the demand sector means an increase in energy demand in a future period, while an increase in energy technologies such as thermal, hydropower, solar photovoltaic (PV), etc, means an increase in production due to the impacts of CV&C. Results for 'commercial' includes schools, hospitals, supermarket, hotels, and other public facilities. Results for 'buildings' are for studies that analysed energy demand at an aggregate scale (e.g. country level energy demand) or total building energy demand in a location. Results for impact assessment on energy technologies where combined with assessment from their respective energy resources. For example, impact assessment on wind turbines are combined with assessment on wind resources such as wind speed, while assessment on hydropower was grouped with assessment on water resources, etc. Finally, two or more studies with conflicting results for impact pattern for an energy technology or energy demand was termed 'inconsistent' as the direction of impact could not be determined.

2.3.5. Collating, summarising and reporting the results

Based on the study findings, results are presented to describe the characteristics features of the study which includes the geographical distribution, journal publication, sector/sources analysed, methods applied and pattern of CV&C impacts on the energy system. In line with a scoping review, a summary of the body of evidence is presented in Section 4, with the gaps in the literature and strengths and limitations of the systematic scoping review. Previous literature reviews on the impact of CV&C on the energy system were reviewed to examine the current state of reviews on the topic.

2.4. Results

The PRISMA flow diagram (Liberati et al., 2009) for this study is shown in Figure 2.3. The literature search yielded a total of 5,062 articles which was reduced to 4,029 after the removal of duplicates. While screening the titles and abstracts, 3,374 studies were excluded, and 655 studies were included for eligibility assessment.

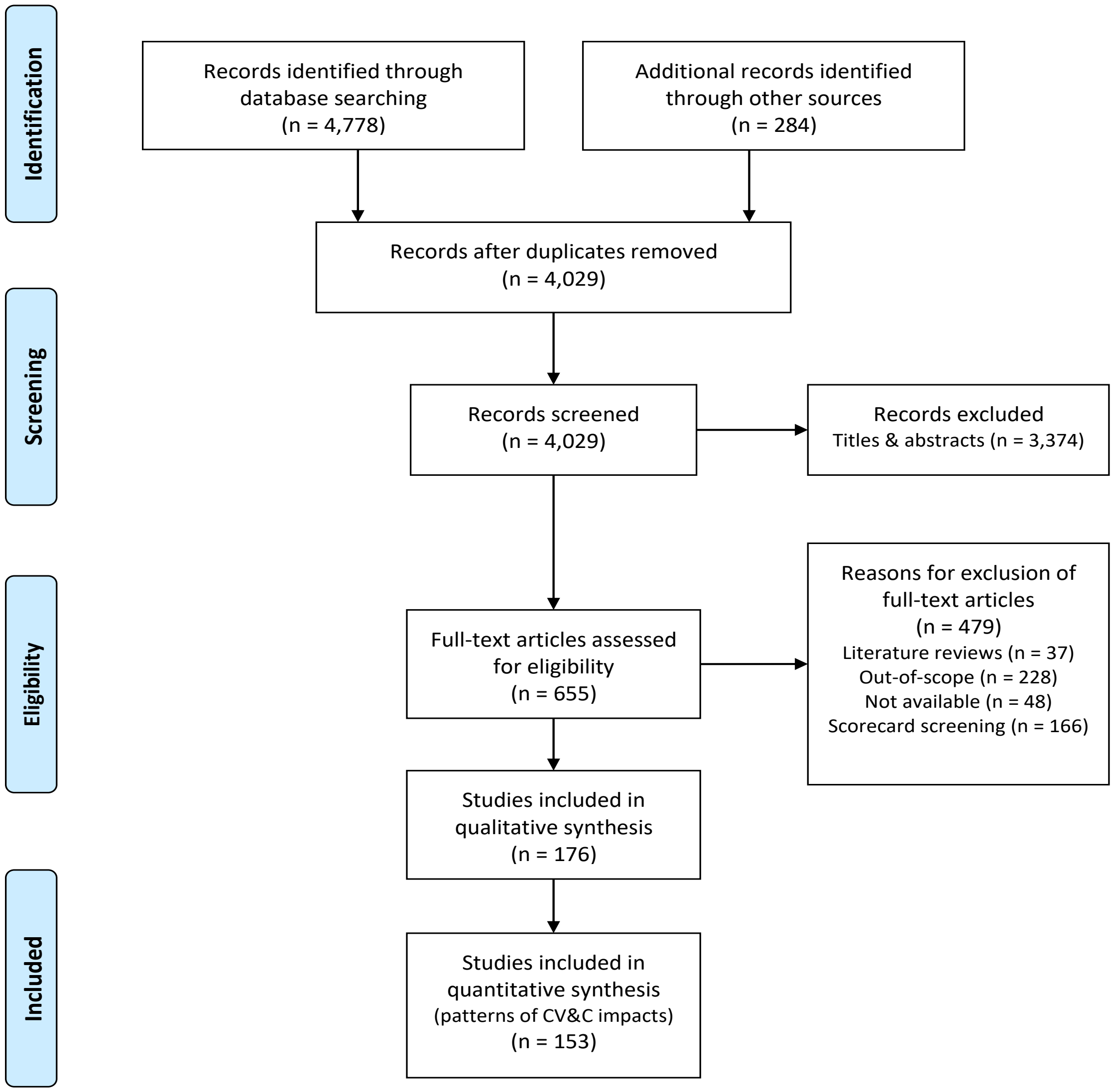

Figure 2. 3: PRISMA flow diagram of studies in the systematic scoping review and reasons for exclusions.

The included studies were screened, and 479 studies were further excluded which includes literature reviews (37), out-of-scope studies (228), articles with no documents available (48) and articles below three-star rating from the scorecard (166). After the eligibility screening, 176 studies were included for qualitative synthesis out of which 153 studies were used for the final quantitative synthesis where the patterns of CV&C impacts were identified. The excluded literature review articles (37) were used to conduct a brief review of the previous literature reviews and after screening, 23 out of 37 review articles were included.

2.4.1. A Review of Previous Literature Reviews

2.4.1.1. An Overview of Previous Literature Reviews

A summary of review studies included for the systematic scoping review and their identifiers are presented in Table A2.3 in Appendix 2 while details associated with the review studies are shown in Figure 2.4. The retained review articles by publication year presented in panel A of Figure 2.4 shows the evolution of literature review studies on climate change impact from 1995 to 2018. Since 1995 till date (2018), review studies on impact of CV&C on the energy system have been growing at an average of 1 study per year, with the most significant increase observed in from 2014-2015 and 2018. Within the observed period, review studies on impact of CV&C on the energy system have been published in 13 Journals, 1 conference proceedings and 2 working papers as shown in panel B of Figure 2.4. The top journals making up the 48% (11 out of 23 articles) of the reviewed studies are *Climatic Change* which has published more CV&C impact studies focusing on the energy system than any journal (4 out of 23 studies). This is followed by *Energy* with three review publications and two studies published in both *Renewable and Sustainable Energy Reviews*, and *Energy Economics*. Although article concentration in a particular journal may depend on the focus of the journal, *Climatic Change* tends to have more influence on topics related to CV&C across a broader range when compared to other journals.

The distribution of sectors, energy sources and technologies covered by the review studies are shown in panel C of Figure 2.4. Although the results showed that the reviews are diversified, hydropower and increasing building energy demand clearly dominates with 21% and 15% respectively. This is followed solar and wind energy had 14% each in the total number of studies.

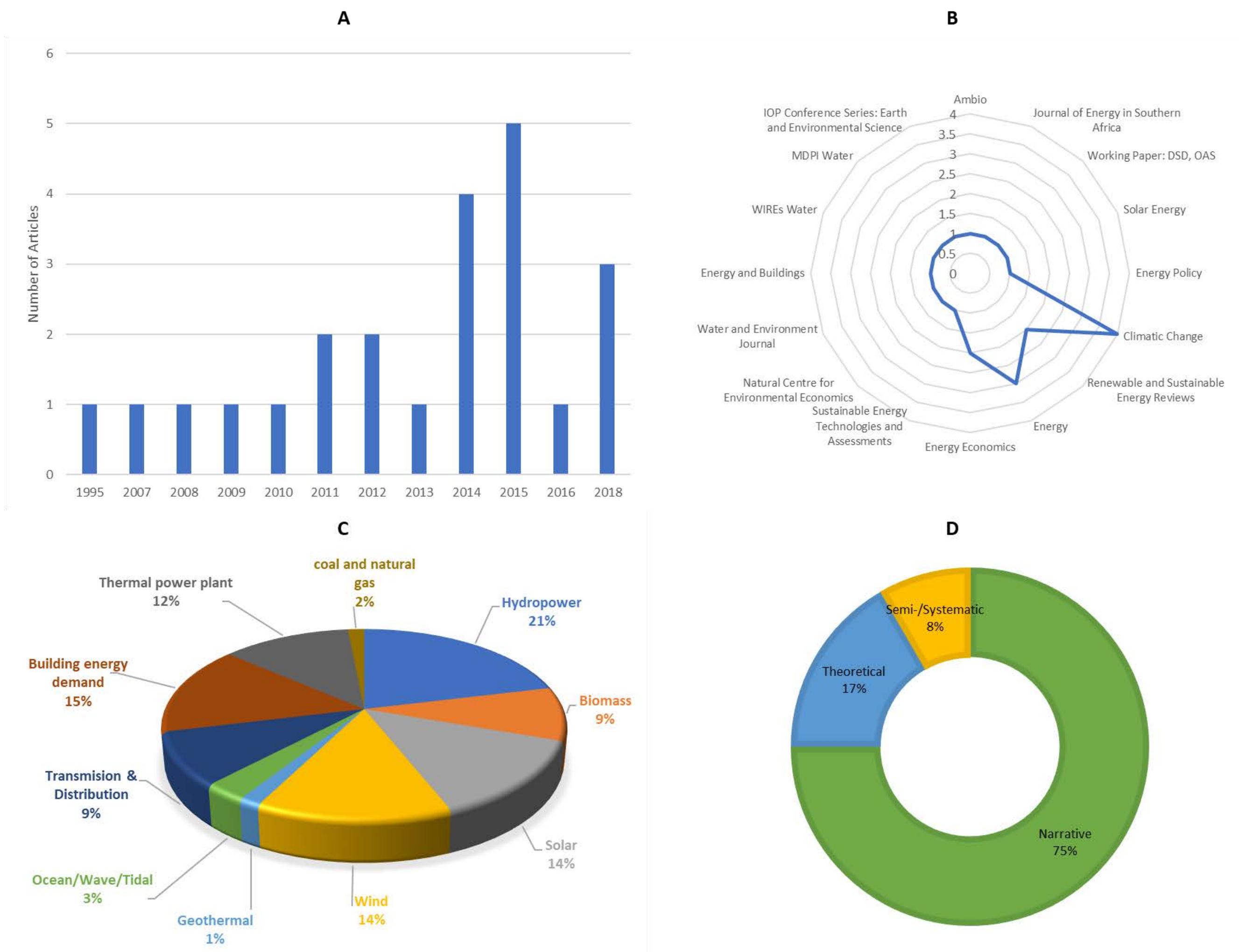

Figure 2. 4: Retained review articles included for the review by publication year (A), the reviewed article per journal (B), sectors/sources covered (C), and review approach applied (D).

As can be observed from panel C in Figure 2.4, the fewer studies have concentrated on energy sources such as geothermal, ocean/wave/tidal, coal and natural gas which occupies between 1-3% of the reviewed studies. This implies that during the period of 1995 to 2018, review studies have been interested in examining the progression of CV&C impacts on hydropower, building energy demand, solar and wind energy systems. The vulnerability of hydropower plant, importance of thermal comfort in buildings, intermittent nature of solar and wind energy may be the contributing factor to the intense focus of the reviewed studies.

The low reviews on coal and natural gas may be due to the progressive view of a sustainable energy future and GHG mitigation, which implies technology switching from fossil fuel to renewable energy source. This aspect will be further investigated in section 3.2 where peer reviewed articles will be analysed. The literature review approach applied in the review studies are shown in panel D of Figure 2.4, where the narrative approach applied in 75% of the reviews studies is the most widely review approach used in review articles on impact of CV&C on the energy system. This is followed by theoretical review studies with 17% and semi-systematic/systematic approach at 8% which is the least applied review method. This reinforces the need for a systematic review which is has been less explored in the literature and a introduces a scoping review approach which to the best of our knowledge, have not been applied in energy or climate related studies.

2.4.1.2. Conclusions from Previous Literature Reviews

The review studies demonstrated some interesting insights into the impact of CV&C on the energy system with most studies reviewing articles on a global scale, while few studies were focused on regional or county level (e.g. Scotland, Sweden, Europe, Southern Africa and Caribbean regions). The review studies identified two common approach for assessment of impact CV&C on the energy system which are degree-days method and simulation techniques (Li et al., 2012a). The simulation models includes impact assessment models which can model both supply and demand side impacts (Cronin et al., 2018).

One shortcoming of the degree-day method as highlighted by Ciscar and Dowling (2014) includes temperature thresholds for cooling degree days (CDD) and heating degree days (HDD) which are kept constant across regions and time. This was further highlighted in Ranson et al. (2014) review where studies show that the temperature at which energy use is minimised varies across geography and time periods. Santamouris et al. (2015) reviewed the literature on the impact of ambient temperature on building energy demand and the studies reviewed showed that for each degree of temperature rise, the increase in peak load varies between 0.45% and 8.5%. This would likely lead to an increase in GHGs from thermal power plants to meet peak demands during summer months. Mitigation options includes alternatives to mechanical AC such as passive ventilation, building indoor design conditions, planning, green or white roofs, insulations, thermal mass, solar shedding, raising set point temperature, reducing lighting load density and regulating internal loads (Hunt and Watkiss, 2011, Li et al., 2012a).

Electricity supply technologies such as hydropower and thermal power plants were identified as the most impacted energy source by CV&C from the reviewed studies. This is due to changes in precipitation and air temperature which can lead to increase in surface water evaporation, reduced run-off due to drought, increased run-off due to flooding and siltation deposits (Mukheibir, 2007, Murrant et al., 2015). Mitigation options for hydropower includes increasing storage capacity and replacing large turbines with multiple smaller ones to allow for flexibility of operations over a wider range of flow conditions. Adaptation options for run-of-river installation are limited to increasing turbine size to take advantage of enhanced winter flows, but flow variance is not restricted to winter events as observed in tropical regions.

For thermal power plants, options include shifting from straight-through cooling to less water using alternative cooling technologies, to a greater use of estuarine and seawater. The efficiency and power output of solar PV depends on its operating temperature (Skoplaki and Palyvos, 2009) and the global increasing temperature will reduce its efficiency (Mideksa and Kallbekken, 2010). The review studies also showed that outputs and efficiency of other renewables such as wind, geothermal, biofuel and ocean energy will be affected by the CV&C during the 21st century (Contreras-Lisperguer and de Cuba, 2008, Schaeffer et al., 2012, Pryor and Barthelmie, 2013).

2.4.1.3. Gaps from previous literature reviews

The reviewed studies highlighted gaps and it was observed that some gaps in a previous review were not addressed in subsequent reviews. For example, Mideksa and Kallbekken (2010) identified limited studies on the impacts of increasing temperature on transmission networks and this was subsequently identified in Chandramowli and Felder (2014) and Cronin et al. (2018). Similarly, Schaeffer et al. (2012) found no study assessing the impact of extreme weather events on energy infrastructure and cross sectoral impacts to account for the complex inter-relationship of the energy sector. These gaps were also identified in subsequent reviews by Chandramowli and Felder (2014), Bonjean Stanton et al. (2016) and Cronin et al. (2018).

Other gaps in the reviewed studies include lack of supply side studies examining the impact of increasing temperature which reduces icing and improve efficiency in wind power plants (Mideksa and Kallbekken, 2010); impacts of CV&C on wind energy in developing countries (Pryor and Barthelmie, 2013); CV&C impacts on thermal power plants and renewable energy in a more holistic view and consider inter-annual or seasonal variations (Bonjean Stanton et al., 2016, Pokhrel et al., 2018). The reviewed studies also identified few demand side studies which includes the possible impacts of CV&C on HVAC[4] system in the future (Yau and Pean, 2011) and adoption of adaptative thermal comfort in current buildings (Li et al., 2012a).

2.4.2. Study characteristics of the literature

2.4.2.1. Geographical distribution

The geographical distribution of the studies by region, country and number of energy technologies analysed are show in Figure 2.5. The studies by country as shown in panel A of Figure 2.5 indicates that most of the published literature on the impact of CV&C on the energy system have improved with studies found in developing countries in Africa and the Asian regions. However, the most studies conducted on the topic has been in the United States of America (USA) (45 articles), China and Germany (12 articles each), Australia and Brazil 11 and 10 articles, respectively. The studies by regions as shown in

[4] Heating, ventilation and air conditioning

the left-hand side of panel A in Figure 2.5 show that although studies focused on European regions tend to dominate the topic, studies in have become visible in northern, western and southern African regions. The studies included for the review were further scrutinised to examine the progress literature has made in investigating the impact of CV&C on energy technologies. This allowed for the identification of countries that were not captured in the panel A and the results are presented in panel B of Figure 2.5.

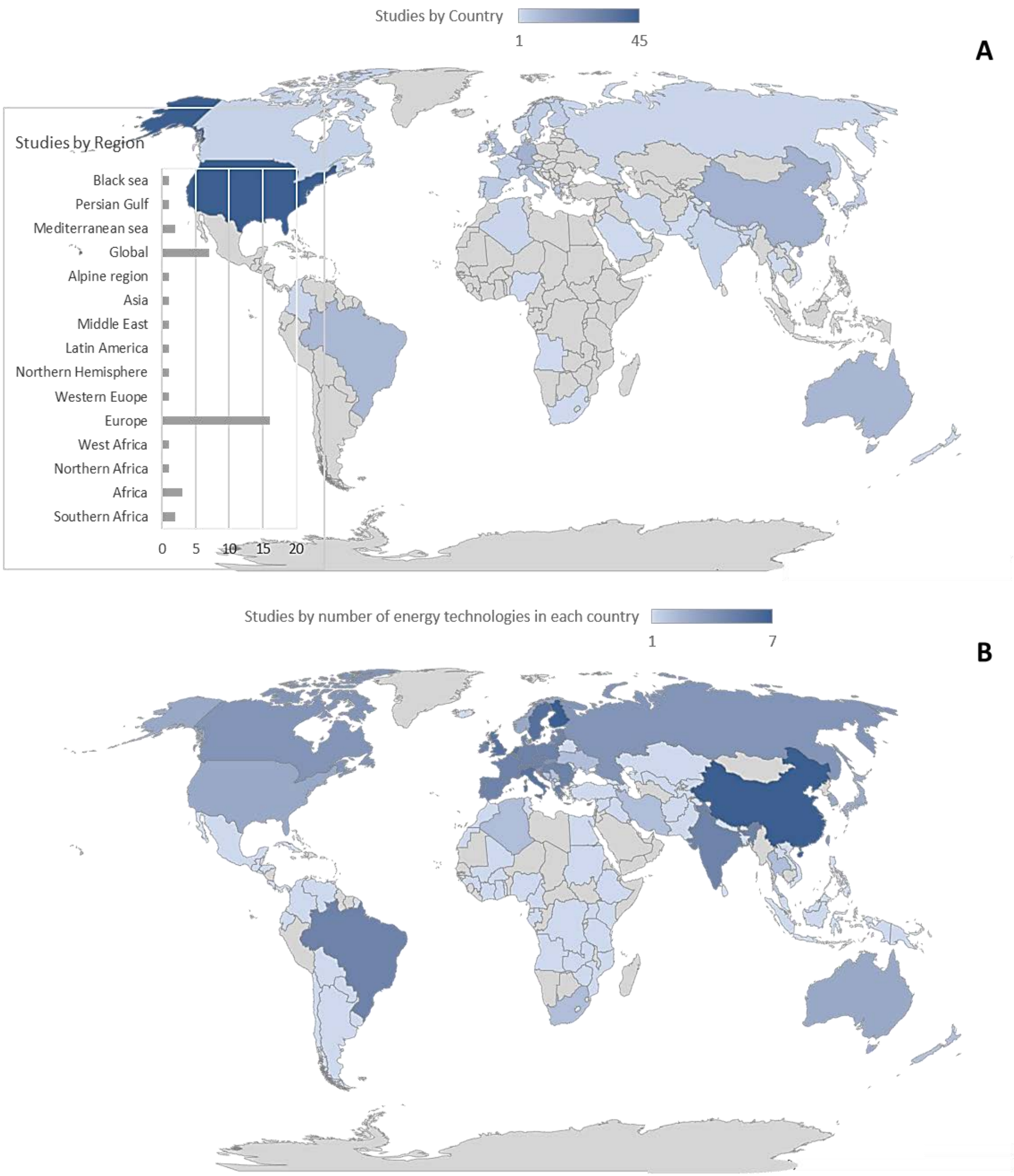

Figure 2. 5: Geographical location of studies selected for the review.

It is clearly observed that more countries were identified based on the number of technologies assessed for the vulnerability to climate change. The most prominent energy technology was hydropower which were observed to have been investigated in almost all the developing countries. This is because the impact assessment was conducted at the catchment or river basin level which can cover various countries with hydropower plants. For example, the study by Pereira-Cardenal et al. (2014) investigated climate impact on the Iberian Peninsula which covers Spain and Portugal, and Popescu et al. (2014) study on climate impact on energy production in La Plate Basin which covers Brazil, Uruguay, Paraguay and part of Argentina. From panel B in Figure 2.5, the countries with higher number of technologies assessed for climate impact are China and Finland (7 technologies each), Italy, Netherlands, Sweden and the United Kingdom (UK) (6 technologies each). The results also show that fewer technologies have been assessed for their vulnerability to climate change in countries located in the African continent, South and Central America and the Asian continent (except Eastern Asia).

2.4.2.2. Journal publications

In Section 3.1.1, literature review articles were analysed based on the journals where the article was published. This was done to identify publication outlets for literature review studies on the topic of CV&C impacts on the energy system. In this section, the studies included for the current review are analysed based on the articles per journal and journal publication by year. Panel A in Figure 2.6 shows the results of article on the impact of CV&C on the energy system published in journals with more than 5 publications between 1990 and 2018. With more than 17 of the 176 total studies, *Climatic Change* has published more studies than any other journal. This is followed by *Energy*, *Renewable Energy*, *Energy and Buildings*, *Energy Policy* and *Applied Energy*. The top eight journals shown in panel A have published 51% (90 of the 176 papers) of the studies to date. The second group of journals with less than 5 publications were eighteen journals in total, representing 26% (45 of the 176 papers) of the studies to date with *Energy Conservation and Management*, *Energies* and *Journal of Hydrology* having 4 papers each during the study period. The last group of journals with 1 paper made up 23% (41 of the 176 papers).

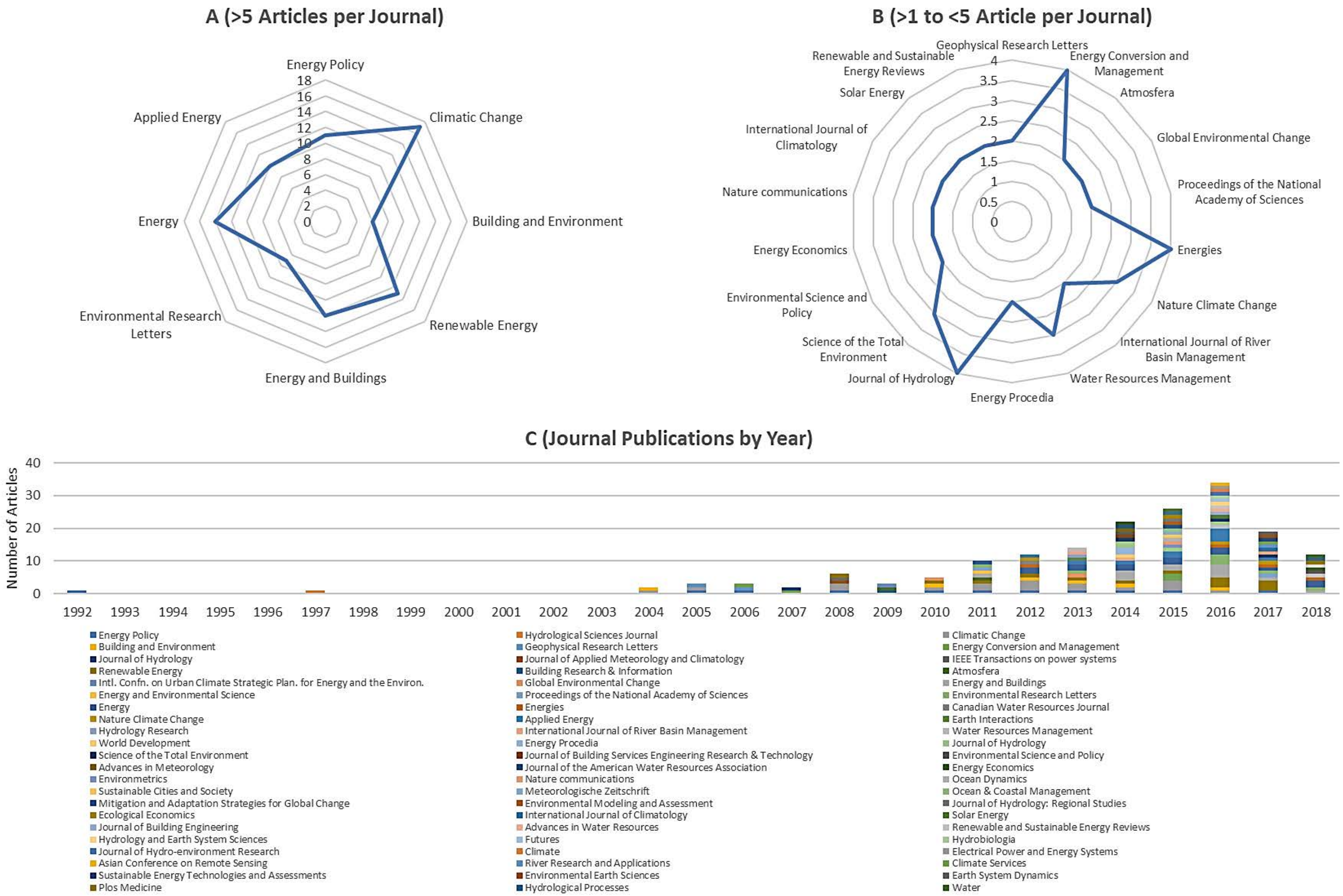

Figure 2. 6: Journal publications of the studies reviewed.

The evolution of the journal publication by year are shown in panel C in Figure 2.6 which also contains the list of journals not mentioned in panel A and B. As can be observed from panel C, *Climatic Change* had the most publication in 2012 and 2015 while *Energy and Buildings* and *Applied Energy* had 4 papers published in 2016 which was the highest for the year. Comparing the outcome of the journals reviewed in this study and the journals where review articles are published as shown in Figure 2.4, it is observed that *Climatic Change* and *Energy Journal* have the highest amount of studies on CV&C impacts on the energy system for the period 1990 to 2018.

However, *Renewable Energy* have maintained a 3 paper per year publication from 2016-2017. The influence of journals towards the papers published is greater when the sector or source assessed for climate impact are ideally the focus of the journal. For example, studies focusing on climate impact on building energy demand have been mostly published in *Energy and Buildings* and *Building and Environment* journals, while studies focused on addressing climate impact on renewables are mostly published in *Renewable Energy* journal. Climatic Change Journal appear to have greater influence on the topic due to its broad scope of examining issues of CV&C on the country, regional and global level.

2.4.2.3. Sectors/energy technologies analysed

The articles reviewed were diversified in terms of sectors/sources analysed for climate impact as shown in Figure 2.7 which also shows the evolution of studies by publication year. The hydropower sector was clearly the most researched energy source for supply side studies with 8 papers per year from 2013-2015 which increased to 15 papers in 2016 and declined to 7 papers in 2017. Other energy sources include wind and thermal power plants with significant number of publications in 2015. On the demand side, the studies focusing on the impact of CV&C on energy demand in an economy had high number of studies published yearly and this may be due to data availability for conducting impact assessment at the aggregated level which is more readily available than disaggregated data for sectoral energy demand. Combining the sectors analysed and sorting them into energy demand, energy supply and electricity networks identifies sectors/energy sources with higher or lower research concentrations as shown in panel B of Figure 2.7.

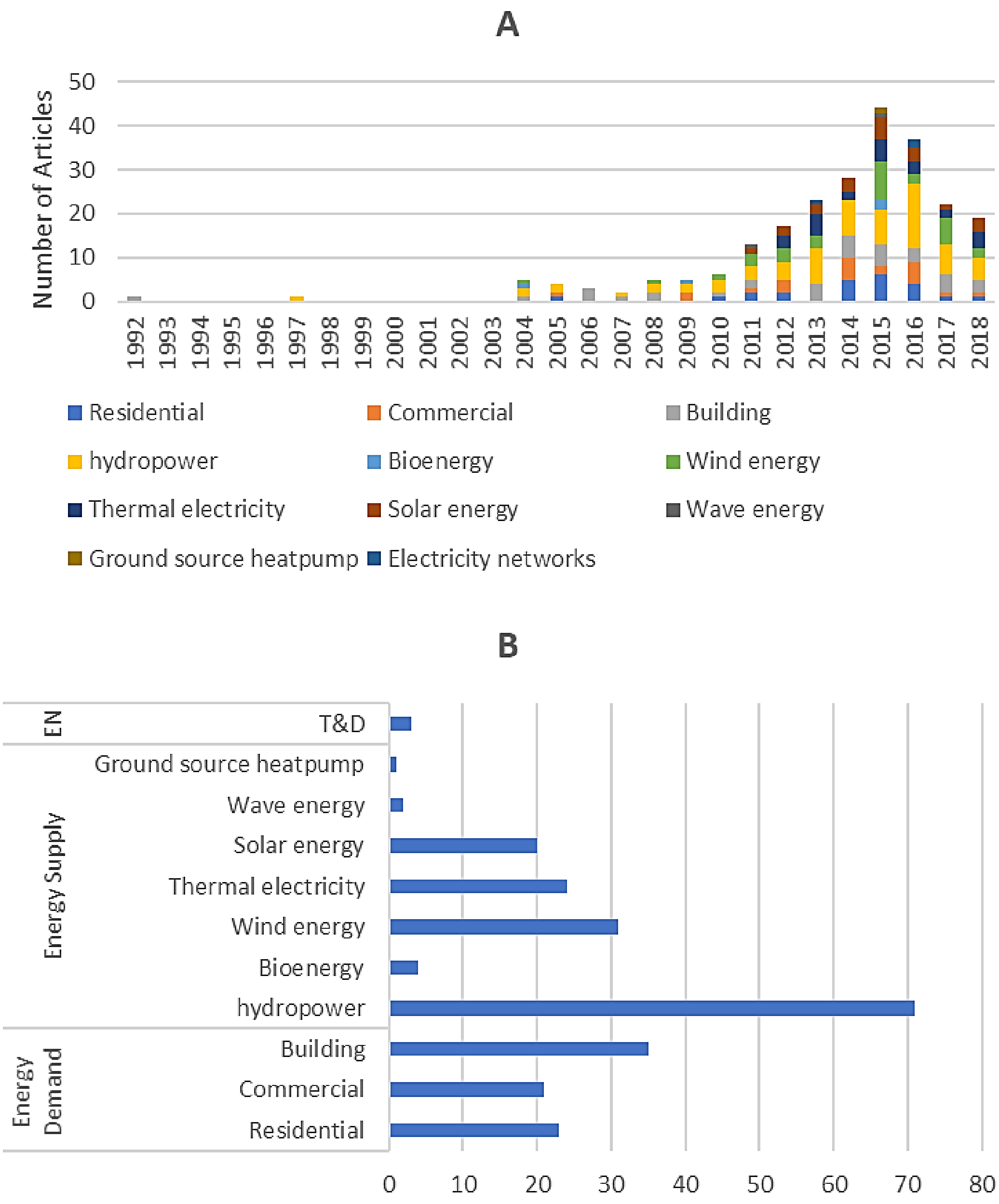

Figure 2. 7: Sectors/energy sources by year (A) and by the total number (B) (EN: electrical networks, T&D transmission and distribution).

Energy supply studies is observed to make up 66% of the total number of studies, with hydropower accounting for 46% of the supply side studies. On the demand side, assessment of climate impact on economywide energy demand made up 44% of the studies reviewed, while residential and commercial sectors had 29% and 27%, respectively. The least researched climate impact on energy sources are ground source heat pump, transmission and distribution networks, wave energy and bioenergy which makes up between 1-2% of the total studies reviewed. This implies that during the period between 1990 and 2018, researchers have been more interested in examining the impact of CV&C on energy supply in general and hydropower in particular. This might be due to the vulnerability of the hydropower sector to climate change which can affect electricity supply as hydropower contributes about 71% of the total renewable electricity and 16.4% of the world's electricity generation by source (Council, 2016).

2.4.2.4. Methods applied

Over the years, a range of methods have been applied to assess the impact of CV&C on the energy system. They range from the less complex approach where GCM data are used as a proxy for climate impacts (e.g. Cradden et al. (2012), Carvalho et al. (2017)) to the more complex method where data from GCM are used as inputs to impact assessment models (IAM) (e.g. POLES used in Dowling (2013a)). The GCM data are retrieved from available climate change projection datasets (e.g. UKCP09 used in Braun et al. (2016)) and in some cases, combined with emission scenarios (e.g. Seljom et al. (2011), Majone et al. (2016)) or adjust the time series to a specific linear trend for the parameter (e.g. Koch et al. (2014)). GCM data used as input in IAM were measured by its distribution, mean and median and varied across the literature.

Built environment such as residential and commercial buildings use electricity for heating/cooling and powering other household appliances. Energy source such as gas and heating oil are mostly used for space heating in buildings. Based on the articles reviewed, the impact of CV&C on energy demand were assessed using multiple linear regression (MLR) and bottom-up energy models. A large amount of demand side studies applied MLR model where climate (e.g. temperature, precipitation) and economic (e.g. price, income) variables are independent variables are regressed with energy/electricity demand as dependent variables.

The coefficients from the MLR model and climate projections are used to estimate changes in future energy demand compared to the base year. Examples of study applying MLR include Li et al. (2014) and Chen et al. (2016). Bottom-up energy simulation model are developed and used to predict future energy use in buildings. Climate data are retrieved from GCMs and integrated within the simulation model. Examples include IDA ICE building simulation software used in Waddicor et al. (2016) and EnergyPlus in Reyna and Chester (2017). Other studies used partial equilibrium model to estimate the impact of CV&C on the energy system (e.g. POLES[5] (Dowling, 2013b, Mima and Criqui, 2015a) and GEMINI-E3[6] (Labriet et al., 2015)).

Electricity generation from hydropower facilities rely on the availability of water resources, seasonal patterns of the hydrological cycle, variation in water inflows, water storage capacity[7] and installed capacity of the power plants (Minville et al., 2009). Climate impact on hydropower production are estimated using hydrological models (e.g. GEOTRANSF[8] applied in Majone et al. (2016), NAM[9], SWAT[10] and MIKE SHE[11] applied in Karlsson et al. (2016)) or simulation models used for electricity dispatch from hydropower plants (e.g. TOPKAPI[12] used in Maran et al. (2014b)). According to Schaeffer et al. (2012), climate change can affect heating and cooling requirements of power plants operating under Rankine or thermodynamic and Brayton cycles and the effect may vary according to the average temperature, humidity, pressure and availability of water.

Coal and nuclear power plants operate under the Rankine cycle and their thermal efficiencies are affected by changes in ambient temperatures (Linrterud et al., 2011). Gas power plants, such as open cycle- and combined cycle- gas or steam turbines, are based on Brayton cycles (Bahrami et al., 2015). The turbine power output, fuel consumption and efficiency of Brayton cycle power plants may be affected by increase in temperature and humidity. Hydrological models such as WaterGAP3 and SWIM have been applied to

[5] The Prospective Outlook for Long-term Energy Systems
[6] General Equilibrium Model of International-National Interactions between Economy, Energy and Environment
[7] With enough storage capacity in reservoirs associated with hydropower units, major fluctuations of precipitation from daily to annual scales can be adequately managed.
[8] GEOTRANSF: a continuous non-linear hydrological model
[9] Danish: Nedbør-Afstrømnings-Model
[10] Soil and Water Assessment Tool
[11] System Hydrological European
[12] TOPographic Kinematic APproximation and Integration

thermal electricity generation as well as regression models used in Linrterud et al. (2011) and LEAP-WEAP[13] model applied in Sun et al. (2018).

Wind speed significantly varies with height (Schaeffer et al., 2012), cannot easily be stored[14] and it is intermittent (Camacho et al., 2011). The impacts of CV&C are assessed by retrieving wind speed projections from GCM as a proxy for wind power production or by extrapolating wind speed for a particular height of the hub of the turbine model being assessed (Bonjean Stanton et al., 2016). Changes in temperature can affect efficiencies of solar PV cells leading to low power output (Skoplaki and Palyvos, 2009). In this study, the impacts are quantified as changes above or below 1% for energy demand sectors or energy supply technologies. The reviewed studies assessed CV&C impacts on solar PV by developing a model of PV power generation based on the change in global radiation and the averaging by distribution of orientations and tilt angles of PV modules within a region (Wachsmuth et al., 2012, Wachsmuth et al., 2013).

For wave energy, methods used in assessing CV&C impacts includes WAVEWATCH III model (Reeve et al., 2011b) and using future downscaled wind data to generate wave characteristics (Kamranzad et al., 2015). Transmission and distribution systems are prone to climate change impacts due to their long delivery distance, which may cause delivery failure of either electricity or energy resources. Some notable climate conditions that affect transmission and distribution systems are flooding, lightning strikes, heavy winds or ice loads, landslides and avalanches (Grigsby, 2016). The impact of CV&C on transmission and distribution infrastructure can be assessed from projections generated from Monte Carlo simulations Ryan et al. (2016).

2.4.3. Patterns of CV&C impacts

The reviewed studies described various patterns of CV&C impacts on energy demand and energy generating technology. This section identifies patterns of CV&C impacts and presents the results at the regional and country levels which are shown from Figure 2.8 – 2.12. In the regional result, more than one result from two studies are included to improve the robustness of the patterns of CV&C impacts on sectors and

[13] Long-range Energy Alternatives Planning System (LEAP) and Water Evaluation and Planning System (WEAP)
[14] Wind power require advanced control techniques in order to achieve high performance and reliable operations.

energy technologies. Inconsistent results are highlighted in yellow colour for the regional level (Figure 2.8 – 2.10) and country level (Figure 2.11 – 2.12) results. In the country result, three level of colour dept are used as a proxy for robust consistent pattern of CV&C impacts. The results are presented in more detail in Table 2.2 where the results from an article reviewed are coded for a specific region or country for an energy demand sector and energy generating technologies.

2.4.3.1. Regional level

The annual consistent patterns for CV&C impacts on residential, commercial, building energy demand, hydropower, wind, thermal, solar PV and wave energy on the regional level are shown in Figure 2.8 – 2.10. This covers the five world regions (Americas, Africa, Asia, Oceania and Europe) and their respective sub-regions for the near-mid 21st century *(NC-MC)* and end of the 21st century *(EC)*. The results are analysed based on the sectors and energy technologies. The results show great variations in pattern of energy demand across regions and time periods. More specifically, this study identifies consistent increase in energy demand for residential and commercial sectors in Southern Europe, the Americas and part of Asia, while decrease is observed in Oceania region, Central and East Asia, Northern and Western Europe.

Building energy demand is projected to experience increase in demand in Africa, Asia, America and Oceania regions but decreasing in Northern and Eastern Europe. From a regional perspective, most individual results from articles showing a consistent pattern of increase or decrease in energy demand are projected to occur in the NC to MC. Also, inconsistent results were fewer compared to consistent results and only one region (Eastern Europe) showed no change in commercial energy demand by EC. This shows that the collective regional studies appear to agree that the effect of climate change on energy demand may occur more sooner than expected. This tends to be in line with the recent warnings by the IPCC (IPCC, 2018b) on the imminent climate change which will have impacts such as extreme heat wave among other impacts.

Table 2. 2: Detailed results for pattern of CV&C impacts on the energy system from the reviewed studies.

Sector/energy source	Consistent pattern				Inconsistent pattern		No change
	Increase		*Decrease*				
	Regional	*Country*	*Regional*	*Country*	*Regional*	*Country*	*Regional/Country*
			Energy demand				
Residential demand	Southern Europe (#80 EC:1), Asia (#20 NT-MC: 5, EC: 5), Americas (#20 NT-MC: 4, EC: 4), Oceania region (#20 NT-MC: 1, EC: 1)	Brazil (6 results), Canada (NC: 1 result, EC: 1 result), Hong Kong (4), China (5), Cyprus (NC: 1, EC: 1), India (4), Iran (3), Japan (NC: 2), South Korea (NC: 1), Sweden (NC: 1), Taiwan (3)	Northern Europe (#32 NT-MC: 1), Western Europe (#32 NT-MC: 1; #80 NT-MC: 1, EC: 1)	Finland (3), Netherlands (MC: 1), Russia (MC: 1, EC: 1), Sweden (EC: 1)	Southern and Eastern Europe (NC-MC: 4)	Sweden (MC: 2)	
Commercial demand	Southern Europe (#80 EC:1), East Asia (#20 NC-MC:1), Southern, Western, Southeastern Asia (#20 NC-MC: 3, EC: 3), the Americas (#20 NC-MC: 4, EC: 4)	Brazil (3), Hong Kong (6), China (NC: 1, EC: 2), Greece (3), Japan (5)	Northern Europe (#32 NT-MC: 1; #80 NT-MC: 1, EC: 1), Western Europe (#32 NT-MC: 1; #80 NT-MC: 1, EC: 1), Central Asia (#20 NT-MC: 1, EC: 1), East Asia (#20 EC: 1), Oceania region (#20 NT-MC: 1, EC: 1)	Canada (MC: 1, EC: 1), Italy (NC: 1, MC: 1), Russia (MC: 1, EC: 1)	Southern, Eastern Europe (NC-MC: 4)		Eastern Europe (EC: 1)
Building demand	Africa (#65 EC-MC: 4, EC: 4), Asia and Americas (#20 NC-MC: 9, EC: 9), Oceania (#20 NC-MC: 1)	Bulgaria (MC: 1), Greece (EC: 2), Italy (8), New Zealand (3), Ireland (MC: 1, EC: 1), Luxembourg, Netherlands, Norway (MC: 3, EC: 3), Poland (MC: 1), Portugal (MC: 1), Romania, Slovakia, Slovenia (MC: 3), Spain (NC: 2, EC: 2), Taiwan (3), Thailand (3), Sweden (EC: 2), United Kingdom (MC: 1, EC: 1)	Northern Europe (#32 NC-MC: 1; #40 NC-MC: 1, EC: 1; #65 NC-MC: 1, EC: 1), Eastern Europe (#65 NC-MC:1, EC: 1), East Asia (#20 EC: 1), Oceania (#20 EC: 1)	Australia (4), Belgium (MC: 1, EC: 1), Canada (MC: 1), China (3), Croatia, Czech Republic, Denmark, Estonia, Hungary, Latvia, Lithuania (MC: 7), Finland (5), France (7), Germany (EC: 1), Portugal (EC: 1), Sweden (MC: 1), USA (EC: 1)	Southern and Western Europe (NC-MC: 4, EC: 4)	Germany (5), Spain (3), Switzerland (6) and USA (5)	
			Energy supply				

Hydropower	Northern Europe (#66 NC-MC: 1, EC: 1; #125 NC-MC: 1, EC: 1; #128 NC-MC: 1, EC: 1; #132 NC-MC: 1), East Africa (#46 NC-MC: 1; #128 NC-MC: 1, EC: 1; #132 NC-MC: 1), Central Africa (#46 NC-MC: 1), Eastern, Southern and Southeastern Asia (#46 NC-MC: 1; #132 NC-MC: 1; #128 NC-MC:1, EC: 1), Northern America (#46 NC-MC: 1; #132 NC-MC: 1)	Angola (MC: 2), Bangladesh (NC: 1, EC: 1), Cameroon (MC: 1) Canada (8), China (EC: 2), Democratic Republic of the Congo, Ecuador and Egypt (MC: 3), Estonia (EC: 1), Finland (9), Gabon (MC: 1), Hungary (EC: 1), Iceland (MC: 1), India (NC: 1, EC: 1), Indonesia (4), Ireland (EC: 4), Japan (NC: 1, EC: 1), Latvia (8), Lithuania (EC: 1), New Zealand (NC: 2, EC: 1), Norway (EC: 2), Russia (MC: 2, EC: 2), South Korea (5), Sweden (EC: 3), Taiwan (3), Kazakhstan, Kenya and Kyrgyzstan (MC: 3), Malaysia (MC: 1), Panama, Papua New Guinea, Philippines (MC: 3), Sri Lanka, Sudan, Tajikistan, Tanzania, Uganda (MC: 5) and Uruguay, Uzbekistan (MC: 3)	Southern Europe (#66 EC: 1; #125 EC: 1; #128 EC:1), Eastern Europe (#66 NC-MC: 1, EC: 1; #80 NC-MC: , EC: 1; #128 NC-MC: 1, EC: 1; #133 NC-MC: 1), Northern Africa (#46 NC-MC: 1; #128 NC-MC: 1, EC: 1; #132 NC-MC: 1, EC: 1), Southern Africa (#46 NC-MC: 1; #121 NC-MC: 1, EC: 1; #128 NC-MC: 1, EC:1; #132 NC-MC: 1, EC: 1), Central and Western Asia, the Americas (#128 EC: 6)	Afghanistan, Algeria and Australia (MC: 3), Albania (6), Angola (NC: 1), Argentina (NC: 1), Belarus (NC: 2, MC: 1), Bosnia-Herzegovina (6), Brazil (NC: 7), Burkina Faso (NC: 1), Colombia (NC: 2, EC: 1), Costa Rica (MC: 1), Croatia (9), France (MC: 4, EC: 4), El Salvador (MC: 1), French Guiana, Georgia, Ghana, Guatemala, Guinea, Honduras, Italy, Ivory Coast, Laos, Lesotho, Mali, Mozambique, Morocco (MC: 13), Greece (NC: 5, EC: 4), Iceland (NC: 1, EC: 1), Iran (EC: 1), Italy (EC: 3), Luxembourg (MC: 2, EC: 2), Macedonia (6), Moldova (NC: 2, MC: 2), Montenegro (NC: 1, MC: 3), Pakistan (NC: 1, MC: 2), Portugal (EC: 3), Paraguay (MC: 2), South Africa (NC: 1, EC: 1), Spain (NC: 4, EC: 3), Switzerland (EC: 4), Togo, Tunisia (MC: 2), Turkey (3), Ukraine (5), Vietnam (NC: 1, MC: 1), Venezuela, Zambia, Zimbabwe (MC: 3)		
Bioenergy production		Finland (NC: 1)		Brazil and Ireland (EC: 2)		
Wind power plants	North Europe (#14 EC: 1; #125 EC: 1), northern and western part of Mediterranean Sea, Black Sea (#63 NC-MC: 3), Baltic Sea (#14 NC-MC: 1, EC: 1), South Africa (#33 NC-MC: 1)	Brazil (4), Greece (5) and India (NC: 1)	South and Western Europe (#14 EC: 2; #125 EC: 2), all parts of the Mediterranean Sea (#41 NC-MC: 1; #63 NC-MC: 3, EC: 4), Black Sea (#63 EC: 1), Northern Africa (#41 NC-MC: 1)	Austria (5), Belgium (NC: 1, MC: 1), Bulgaria (3), Cyprus (3), Czech Republic (3), Denmark (NC: 1), Estonia (3), Finland (MC: 1, EC: 1), France (5), United Kingdom (NC: 1, MC: 1), Hungary (3), Ireland, Italy (10), Latvia, Lithuania, Luxembourg (9), Netherlands, Poland (NC: 2, EC: 1), Portugal, Romania, Spain (15), Slovenia (3), Sweden (NC: 1, EC: 1), Switzerland (3), Taiwan Strait (3)	Northern and Southern Europe (NC-MC: 6) and Eastern Europe (NC-MC: 3, EC: 3)	Belgium (EC: 1)

Thermal Power plants	Eastern Asia (#150 EC: 1), Southeast Asia (#132 NC-MC: 1; #150 NC-MC: 1)	Italy (NC: 1) and Serbia (NC: 2, MC: 1)	Southern Europe (#32 NC-MC: 1; #80 NC-MC: 1, EC: 1; #131 NC-MC: 1; #132 NC-MC: 1; #133 NC-MC: 1, EC: 1), Western Europe (#32 NC-MC: 1; #40 NC-MC: 1, EC: 1; #80 NC-MC: 1, EC: 1; #131 NC-MC: 1; #132 EC: 1), Eastern Europe (#32 NC-MC: 1; #80 NC-MC: 1, EC: 1; #132 NC-MC: 1; #132 NC-MC: 1; #133 NC-MC: 1, EC: 1), Western and Southern Africa (#132 NC-MC: 2, EC: 2), Central, Southern and Western Asia (#132 NC-MC: 4; #150 NC-MC: 4, EC: 4), North America and Oceania regions (#132 NC-MC: 2, EC: 2; #150 NC-MC: 2, EC:2)	Australia (NC: 1, EC: 2), Belgium (EC: 1), Bosnia-Herzegovina (MC: 1), Brazil (NC: 1), Bulgaria (EC: 1), China (NC: 1, MC: 1), Croatia (4), Czech Republic and Estonia (EC: 2), Finland (3), France, Germany (EC: 4), United Kingdom (EC: 3), Greece (EC: 2), Hungary (EC: 1), Ireland (NC: 1, EC: 1), Italy (EC: 2), Latvia (3), Lithuania, Poland, Romania, Slovakia, Slovenia (EC: 5), Netherlands (EC: 2), Norway (MC: 1), Macedonia (MC: 1), Montenegro (MC: 1) Portugal (EC: 4), Russia (NC: 1, MC: 1), Spain (EC: 2), Sweden (NC: 1, EC: 2), Switzerland (EC: 2) and USA (3)	Northern Europe (NC-MC: 5, EC: 2) and Southeast Asia (EC: 2)	Estonia (NC: 2)	North, East and Central Africa (#132 NC-MC: 3, EC: 3), Central and South America, the Caribbean and Oceania regions (#132 NC-MC: 4, EC: 4; #150 NC-MC: 4, EC: 4)
Solar photovoltaic	Southern Europe (#51 EC: 1), North Africa (#48 NC-MC: 1), South Africa (#33 NC-MC: 1), Central America, the Caribbean and Oceania (#22 NC-MC: 3; EC: 3; #48 NC-MC: 3; #146 NC-MC: 3)	Croatia (3)	Northern, Southern, Western and Eastern Europe (#32 NC-MC: 4; #51 EC: 3), Central, East and Western Africa (#48 NC-MC: 3), Asian region (#48 NC-MC: 5; #146 NC-MC: 5) and South America (#22 EC:1)	Algeria (5), Australia (5), Austria, Bulgaria (6), Belgium, China (NC: 2), Cyprus, Czech Republic, Estonia (9), Denmark (NC: 1, MC: 1), Finland (3), France (3), United Kingdom (NC: 1), Hungary (3), India (2 for NC and MC), Ireland (NC: 1, MC: 1), Italy (3), Latvia (3), Lithuania (3), Netherlands (3), Poland (3), Portugal (3), Romania (3), Slovakia (3), South Africa (NC: 1, MC: 1), Spain (EC: 1), Sweden (3) and Switzerland (3)	South America (NC-MC: 3)	Germany (10), United Kingdom (EC: 2), Greece (6) and Spain (4)	North America (#146 NC-MC: 1)

Coding interpretation: '#xy' number identifies an article included for the quantitative review which is available in Table A2.2 in Appendix 2; the NC, MC and EC means near century (2010-2039 or 2030s), mid-century (2040-2069 or 2050s) and end of century (2070-2099 or 2080s), respectively; ':xy' numbers denotes the number of individual results from a particular article which is shown on the right side of Table A2.2 in Appendix 2. Note that the quantification of increase and decrease in energy demand and supply from the articles reviewed and coded in Table 2 are based on percentage changes of more or less than ± 1%. i.e. an increase less than 1% or decrease less than -1% is not considered a significant impact of climate change on energy demand or energy supply technologies presented in Table 2.

On power supply technologies, no inconsistent results were identified in the pattern of climate change impacts on hydropower production. However, unlike the case of energy demand sectors, the results for the articles reviewed showed a balance between climate impact for the NC-MC and EC time periods. More studies tend to agree on the consistent increase in hydropower generation in Northern Europe which will be due to rise in precipitation as the rate of glacier melt increase as a result of global warming. The increase in precipitation will require an expansion or upgrade of hydropower facilities to accommodate the increase water runoffs and reduce losses due to water spillage. Hydropower production in other European regions are projected to decline in other European regions, Northern and Southern Africa, the Americas and part of Central and Western Asia.

Decrease in power output from thermal power plants were identified in the studies reviewed due to decreasing precipitation and higher temperatures which lead to a reduction in available cooling water for power plant operation. The regional results show that the European region, Western and Southern Africa, Western, Southern and Central Asia, North America and Oceania regions will experience reduction in thermal power plant generation. This review identified Eastern and Southeast Asia as the region expected to have higher thermal power generation under climate change conditions.

The results of the review for solar PV systems were either increase or decrease in the consistent pattern of CV&C impacts. Although the impacts were mostly lower in term of percentage change (<3% impacts in most papers) when compared to thermal and hydropower production, increase in solar PV is projected for Southern Europe, Northern and Southern and Africa, Central America, Caribbean and Oceania. With CV&C impact on solar PV system less than 3% in most studies, the technology is practically not endangered in its relevance for the current and future energy system. Power generation for wind energy installations is projected to increase in Northern Europe, parts of the Mediterranean, Black and Baltic Seas and South Africa. No consistent or inconsistent pattern of impacts for regional results were identified for bioenergy production.

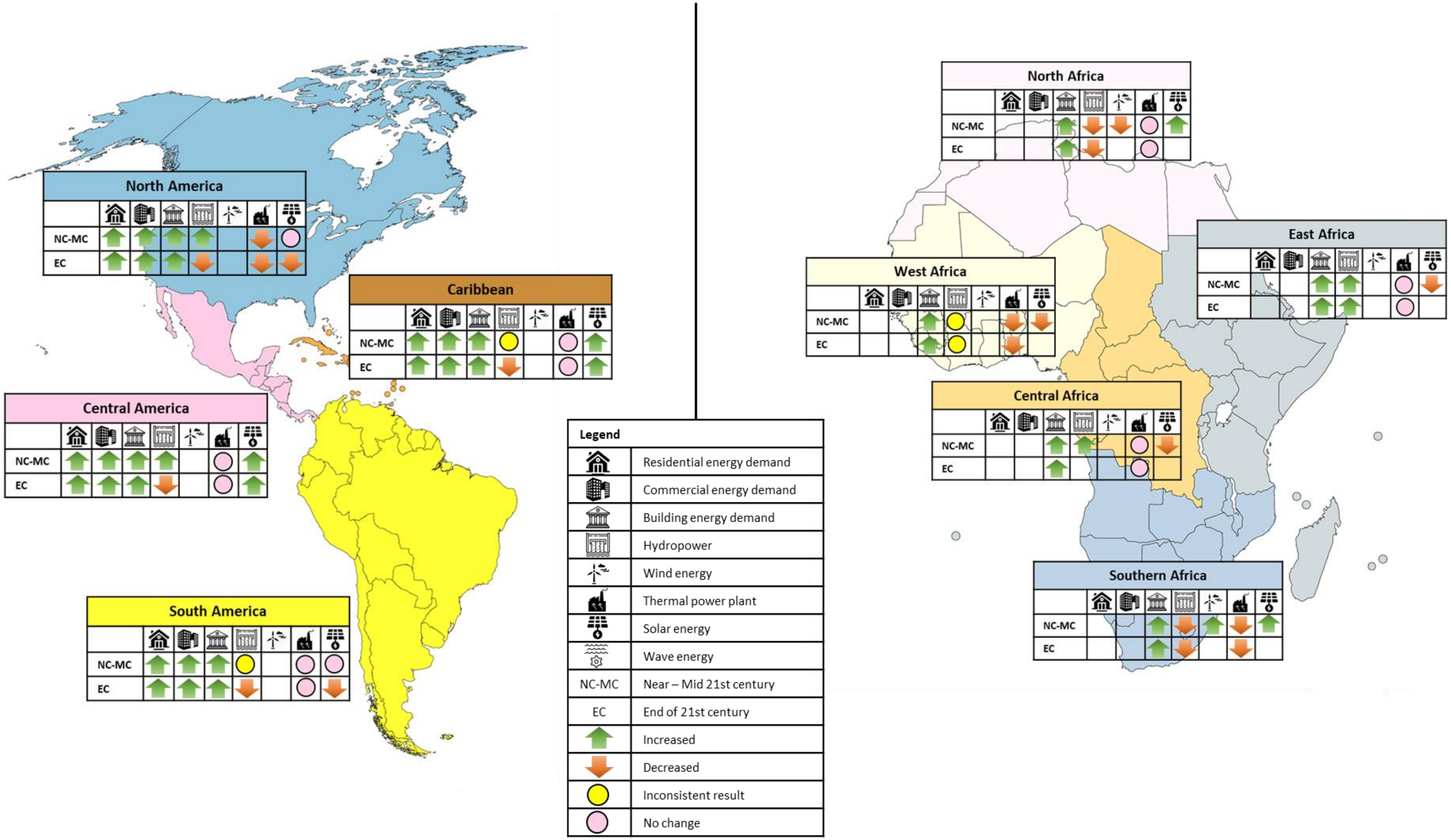

Figure 2. 8: Annual consistent patterns of impacts of CV&C on energy consuming sectors and technologies in the Americas and Africa.

(Icons retrieved from www.flaticon.com)

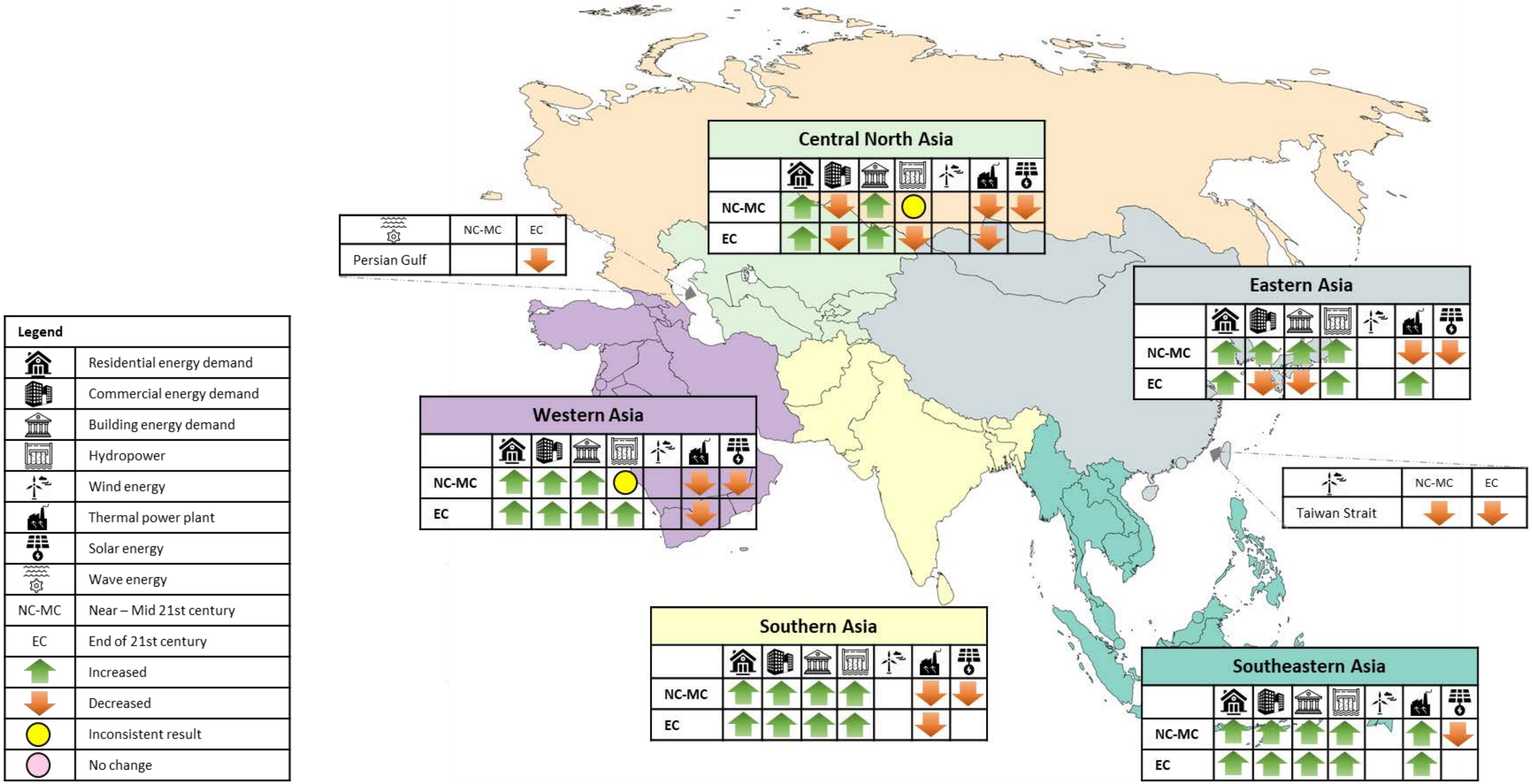

Figure 2. 9: Annual consistent patterns of impacts of CV&C on energy consuming sectors and technologies in Asia.

(Icons retrieved from www.flaticon.com)

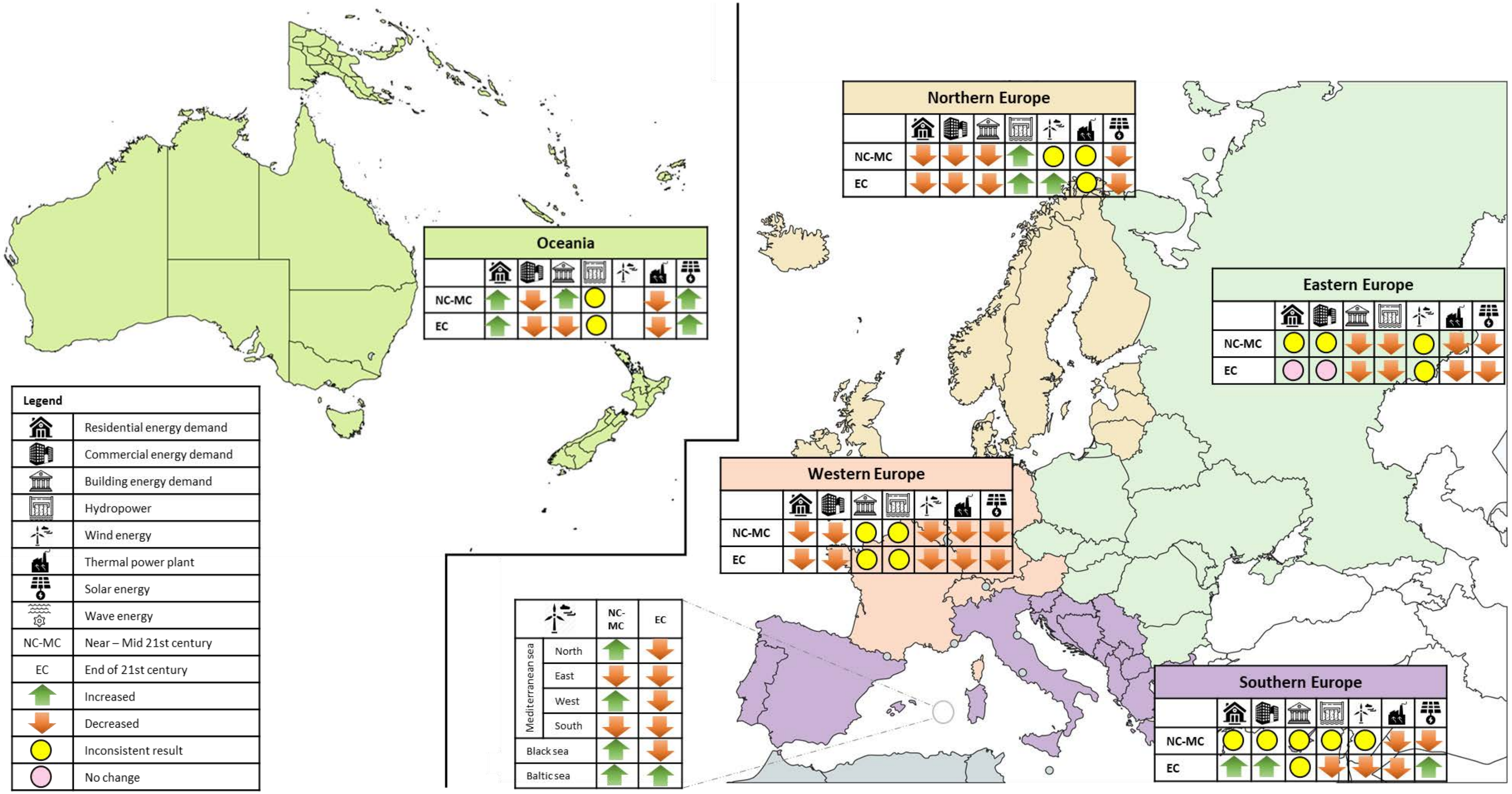

Figure 2. 10: Annual consistent patterns of impacts of CV&C on energy consuming sectors and technologies in Oceania and Europe.

(Icons retrieved from www.flaticon.com)

2.4.3.2. Country level

At the country level, annual patterns of CV&C impacts on energy demand sectors and energy generating technologies appear in Figure 2.11 – 2.12. Each figure is divided into ten panels from the letter A-J for residential, commercial, building, hydropower, bioenergy, wind, thermal, solar PV, wave and transmission and distribution(T&D). The colour patterns are similar to the regional results which represents the level of robustness for each energy technologies. A close observation of the two figures reveal that panel A-D representing impacts of CV&C on residential, commercial, building and hydropower as the most researched areas in the literature compared to other areas of CV&C impact assessment on the energy system. Scanty literatures on the impacts of CV&C includes bioenergy, wind, thermal, solar PV, wave and T&D for the *NC-MC* and *EC* periods.

It can be observed that more results from studies are available for the *NC-MC* than the *EC*, especially for developing countries in Africa and Asian continents. Other inconsistent results (represented by yellow colour in the two figures) were found in the *NC-MC* results (Figure 11) than the EC results (Figure 12). This implies that *EC* projections are more consistent across GCMs than projections from *NC-EC*. However, it is important to note that the results were initially developed for the near, medium and end of the century, but the near and mid-century results were combined to form the *NC-MC*. The detailed results and their respective studies at the country level are presented in Excel file in the Appendix 3.

Also, due to the large number of countries identified, the citation will not be mentioned but the number of results included for the country. The results for USA and Australia's state-level results are show in Figure A2.1 – A2.3 in Appendix 2. From the country-level energy demand results in Table 2.2, it can be clearly observed that more countries will experience an increase in energy demand due to global warming as compared to countries projected to have a decrease in energy demand. However, the consistent pattern of CV&C impacts will mostly occur during the MC and EC time periods as shown by individual results from the articles reviewed. This slightly differs from the regional results where most results showing consistent pattern of increase and decrease during the NC and MC time periods.

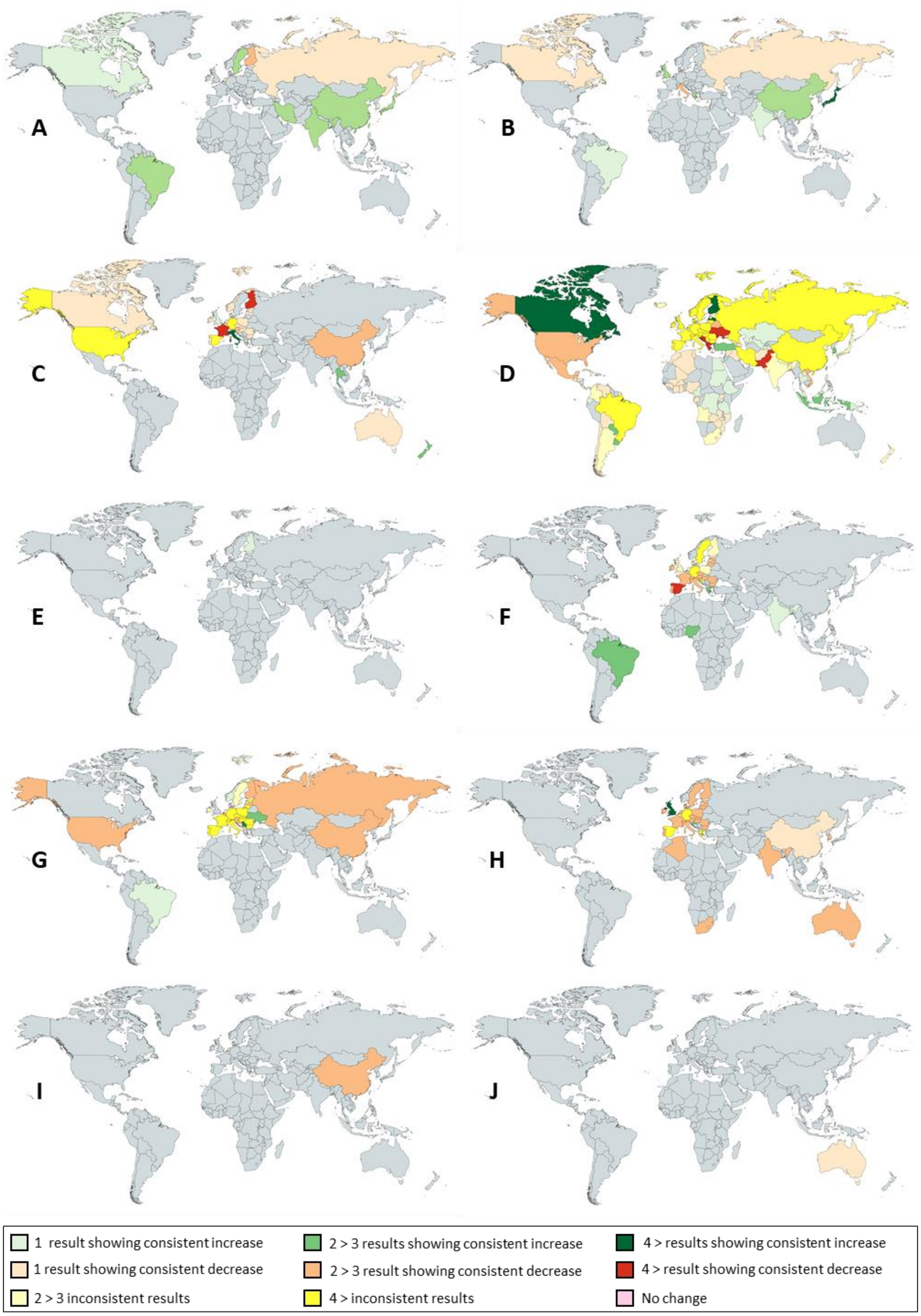

Figure 2. 11: Annual patterns of impacts of CV&C-ES for NT-MC.

(A: Residential, B: commercial, C: economy, D: hydro, E: bioenergy, F: wind, G: thermal, H: solar, I: wave, J: T&D)

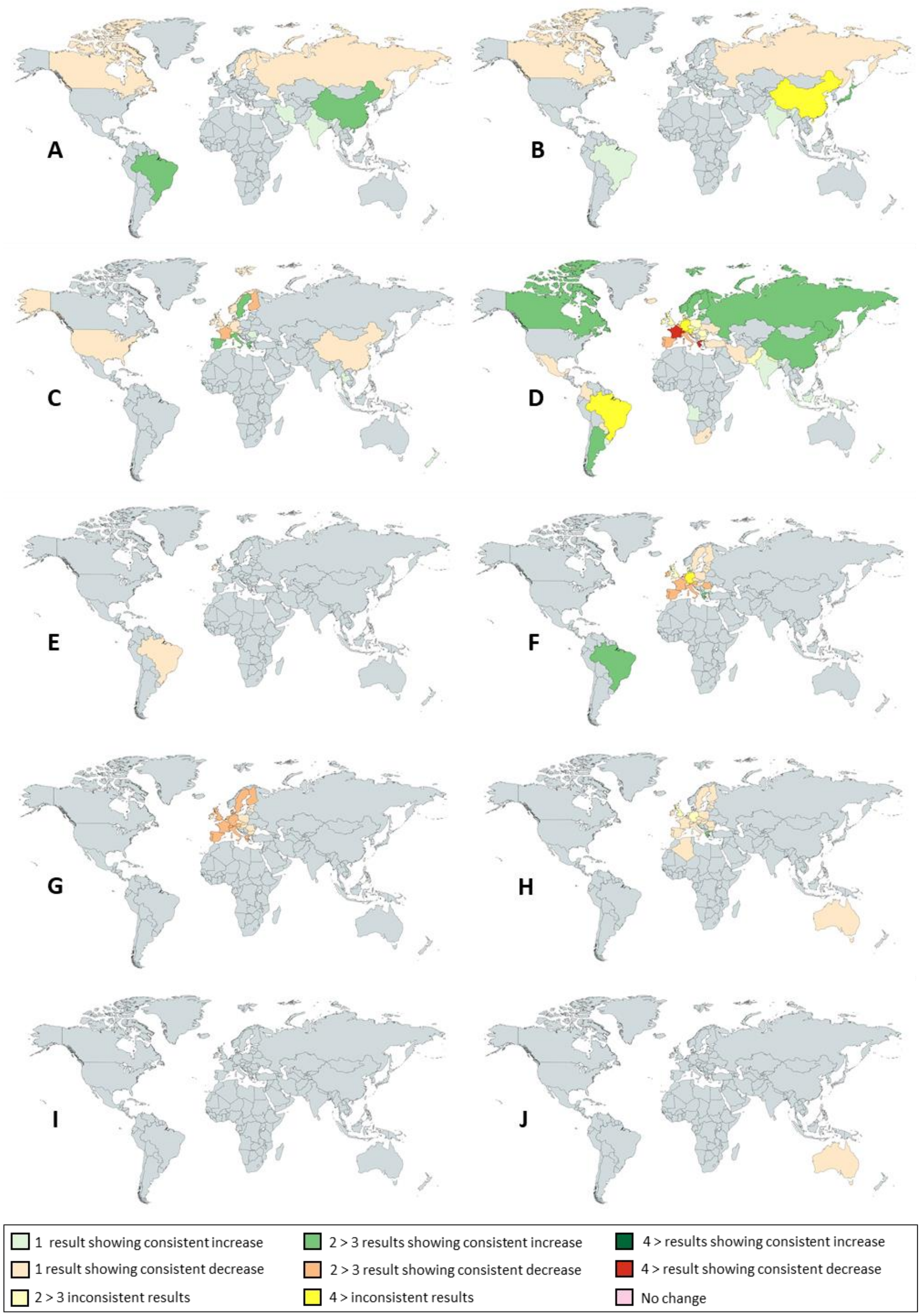

Figure 2. 12: Annual patterns of impacts of CV&C-ES for EC.

(A: Residential, B: commercial, C: economy, D: hydro, E: bioenergy, F: wind, G: thermal, H: solar, I: wave, J: T&D)

This implies that if an average is taken for changes in energy demand across the regions and country-level results, the MC tend to have the most impact of projected changes in energy demand across the studies reviewed. Unlike the regional results, the country-level results show that fewer countries will experience an increase in thermal power, solar PV and wind energy generation compared to countries projected to have a decline in power output from the energy technologies. The reviewed studies show that the decreases projected for thermal power plants are for once through cooling system (Tobin et al., 2018, Van Vliet et al., 2013), while the results show no consistent pattern of impacts of CV&C on power plants with closed-cycle cooling system. Country-level results show that about 31 countries were identified to have a consistent pattern of increase in hydropower production, while individual results from the reviewed study projected a consistent decline in 50 countries around the world.

2.5. Discussion

2.5.1. Summary of the body of evidence

This systematic scoping review was performed to examine the typology, extent and results of existing research conducted on CV&C impacts. To the authors' knowledge, this is the first scoping review to systematically assess both the current state of literature on CV&C impacts on energy system at a global level. At the regional level, the results showed a consistent increase in energy demand due to impacts of CV&C for the Americas, Africa and Asian continent (except for commercial sector in Central/North Asia and Eastern Asia by end of 21st century). Consistent decrease in energy demand was found in Northern and Eastern Europe, while increase in residential demand was projected in Oceania regions. In terms of energy supply technologies, consistent decrease in thermal power plants output were projected in Northern America, parts of Africa, across Asia, Oceania and Europe. Renewable energy technologies such as solar PV showed a robust consistent pattern of increase in the Caribbean and Central America, Northern and Southern Africa (by near century), and in Oceania regions from the near to end of the 21st century.

The reviewed studies agree on the pattern of global temperature increase, but inconsistent precipitation pattern. This is projected to increase energy demand for cooling, while commercial buildings will be more affected than the residential buildings due to contribution from internal heat loads (e.g. office equipment). Although this might be specific to some regions, Auffhammer and Aroonruengsawat (2011) concludes that cooling requirement for residential buildings are higher than commercial sector. This is because the influence of outdoor temperatures is lower compared to contributions from internal heat loads in commercial buildings which closes at night, compared to residential buildings were outdoor temperature and internal heat loads contributes to increase in cooling requirement for a larger part of the day. The consumption will be higher during summer night when climate change increases demand for cooling in the residential homes compared to commercial buildings (Seljom et al., 2011). Globally, studies show that heating demand fuel (e.g. natural gas) will decline while cooling demand fuels (e.g. electricity) will increase. In some temperate regions, this will be due to warmer summer (Parkpoom and Harrison, 2008), while colder regions will have an overall decrease in energy demand due to warmer winter and reduced requirement for heating (Wang et al., 2010).

The results also highlight the vulnerability of hydropower plants to CV&C as precipitation patterns are projected to change across the world. Most projections show an increase in hydropower generation during winter months and reduction during summer months. The decrease during the summer is due to factors such as peak air-conditioning demand (Hamlet et al., 2010) and climatic factors such as decrease precipitation and increasing temperature which leads to greater evapotranspiration (Oni et al., 2012). The decrease in precipitation results in decrease streamflow and reduced utilisation capacity, hence hydropower potential (Aronica and Bonaccorso, 2013). In some regions, the loss in hydropower potential during summer months can be compensated by increased precipitation during winter periods (Carless and Whitehead, 2013). Similarly, the operation of thermal power plant relies on the availability of cooling water to condense steam from the turbine exhaust and cool the system. A potential impact of CV&C is the reduction of thermal power generation due to lower river discharge (from lower precipitation pattern) and higher river temperatures (Popescu et al., 2014).

2.5.2. Implications from the Review

The findings from the reviewed studies show that changes in temperature will have important implication on energy demand for cooling and heating, reduction in efficiency of thermal power plant and significant changes in wind and hydropower production. This will also result in significant changes in electricity market as electricity companies and power distribution networks will have to upgrade their facilities to accommodate the changes due to global warming. As energy demand is projected to decrease in Northern Europe and increase in Southern Europe due to changes in heating and cooling demand, the power supply system will also be impacted upon. The impact on power supply system will be based on changes in the electricity supply priorities and impacts of CV&C on power output such as power plant efficiency.

In countries or regions where power supply from thermal power plant is projected to be affected tend to have power output from renewable sources increase (e.g. wind and hydropower in Northern Europe, Brazil and India, among others). An important implication for such differences could be a results of price differentials which will give incentives to boast power transmission from regions of lower demand to regions of higher demand. Also, there will be an added incentive to invest in generation capacity expansion in regions or countries projected to have higher energy demand than others with projected decrease in energy demand. However, it's unclear how these changes will shape the future energy system in different countries and regions, but the progressive view is a future where fossil fuel is phased out and replaced with renewables.

Advancing towards a renewable and sustainable energy system despite the looming climate change conditions will require power companies to incorporate climate change when building, redesigning or expanding power generation capacity. However, the literature reviewed show a dearth of guidelines specifying how power companies can incorporate changes during capacity expansion, especially in the case of hydropower plants (Lumbroso et al., 2015). Although in developed countries, the guidelines to safe-guard future energy technologies may be available, this information is lacking in some developing countries. Also, if the guidelines are available, the required skills might be quite challenging. Therefore, it is vital for power companies and policymakers to work together with other stakeholder to improve on planning, design and redesign, and operations of power plants to withstand future climatic conditions and avoid maladaptation to climate change.

2.5.3. Potential Mitigation and Adaptation Measures

Combating climate change will require the collaborative efforts of building designers, owners and the government. A simple method for building owners is to adjust the thermostat to use higher cooling setpoint during summer and lower heating setpoint temperatures during winter (Waddicor et al., 2016). Building designers can increase insulative index of the glazing material to enhance solar heat gain and envelope insulation for exterior walls and roofs requirement to reduce envelope loss (Huang and Hwang, 2015, Karimpour et al., 2015). A flexible ventilation system such as the displacement ventilation and underfoot air distribution system can improve air flow pattern in buildings, reduce ventilation load and building energy consumption (Wang and Chen, 2014). Government policies such as the European Union initiatives on near zero energy buildings, provision and economic incentives for refurbishment of older buildings can reduce expenditures, mitigate the increase in GHG emissions and contribute towards adaptation since energy efficient buildings are less vulnerable to CV&C impacts (Zachariadis and Hadjinicolaou, 2014).

Furthermore, appliance efficiency improvement in residential buildings and adjustment of heating, ventilation and air conditioning system (HVAC) operational hours in commercial buildings has the potential to offset projected increase in energy demand due to climate change and this can be effective when coupled with supply-side strategies (Reyna and Chester, 2017, Wang et al., 2017). On the supply-side, hydropower dams should be designed to accommodate sufficient capacity to take advantage of higher winter flows (Park and Kim, 2014), but should not be oversized for actual inflow as indicated by Gaudard et al. (2013). However, expansion or construction of new storage capacity for dams and reservoirs could modify the natural landscape which may affect aquatic life and may not be acceptable by local communities. In this case, promoting renewable electricity as a global/long-term objectives may be in conflict with protecting aquatic ecosystem as a local/short-term objectives (Maran et al., 2014b).

The expansion of dams to accommodate increased inflow may not necessarily result in more hydropower generation. This is because during period of extreme precipitation, reservoirs are forced to spill water without power generation to avoid overloading the dam structures. During the following summer months, reservoir drops to lower levels with low power generation, hence no advantage is gained from increased precipitation (Tarroja et al., 2016). Strategies for adaptation includes increasing hydropower plant efficiency to 10% to mitigate mean annual impacts of increased water constraints under climate change Van Vliet et al. (2016). For thermal power plants, measures include changing the cooling system of power plants from once-through to a closed-circuit or dry cooling system which is shown to be more robust to the effects of CV&C and declining flows due to human activities such as irrigation (Koch et al., 2012, Van Vliet et al., 2012).

2.5.4. Gaps in the literature review

This systematic scoping review shows that despite the growing body of literature examining the impacts of CV&C, there appear to be important gaps in the literature. Also, research gaps identified in previous reviews were not addressed in subsequent studies. Studies have considered the impact of climate change on air conditioner penetration; however, few studies have examined the considerable changes in efficiency improvement and market saturation of other heating and cooling technologies in future periods. The studies reviewed assume a constant load factor and energy demand pattern, but future climatic conditions may alter consumer or occupant behaviour. Therefore, future studies need to account for changes in occupant behaviours in buildings. Few studies considered the effect of price change, but the authors found no study examining price change due to improvement in energy efficiency under climate change. Even fewer studies analysed the risk of new adaptative building design strategies utilising natural energy flows in air materials.

Little assessment of the direct and indirect impact of climate change on hydropower generation. This includes environmental implication (e.g. extreme events), possible damages associated with hydrologic changes and shutting down hydropower plant due to floods. The authors found no study exploring the effect of glacial melt on summer low flows, late summer and ground water recharge on hydropower production. Glacier melting will become relevant in regions where glaciers are going to disappear in the next decades. This is the case for South America (high impact for Peru) and in some parts of the European Alps.

This will have severe consequences for major electricity supply companies in countries such as Iceland where projections show a 25% decrease in glaciers volume from 2000 to 2050 (Sveinsson, 2015). This will result in increased runoff on hydropower production capacity, hence, require an increase or redesign of its power generation, transmission and distribution system as global warming becomes more intense. However, recent studies such as Schaefli et al. (2019) examined the role of glacier retreat for Swiss hydropower production and showed that reduction in production from 2040 to 2090. Therefore, it may be interesting to identify how strong the dynamic interaction will be between global warming, glacier melt and hydropower production in the coming decades.

Articles explored the impact of CV&C on cooling water availability, but to the author's knowledge no study considers current and future configurations of thermal power plant cooling equipment. Fewer studies examined the impact of CV&C on T&D infrastructure and even fewer studies have considered the cost implication of improving the transmission grid (e.g. direct current transmission lowers T&D losses) and applying mitigation options to reduce the impact of rising temperatures. Other limited studies include studies investigating power sector decarbonisation under climate change while few applied fixed emission factors and linking emissions back to the GCM data.

For wind energy technologies, the impacts of CV&C on offshore wind potential was the least explored in the literature review. Few studies on solar PV considered the impact of CV&C on solar cells or PV materials and how future solar radiation might affect adjustable or fixed tilt angles of solar panels. Adaptation and mitigation measures applied in the literature on CV&C impacts has not fully qualified the costs and benefits of each measures to the energy system. Technological innovation for future energy technologies is not considered in the reviewed studies. Assessment should examine cross-sectoral linkages, back-loops and include a complete climate system assessment model with more realistic representation of sea ice, ocean and ecosystem responses.

Also, the integration of supply side impacts with demand side impacts should consider socioeconomic dynamics (e.g. effects on population density reflecting climate-related migrations). The current studies can be improved by considering the implications of long-term effects of CV&C on an optimised energy system. The studies reviewed showed that despite the advancement of the knowledge frontier, there are still sparse studies on CV&C impacts in developing countries and uneven impact assessment of energy technologies. These technologies include bioenergy, wind, thermal, solar, wind and wave energy, while limited studies addressed CV&C impacts on T&D networks. Also, there are more near to middle century studies compared to end of the 21st century impact assessment literature.

Finally, the reviewed studies placed little emphasis on the implications of uncertainties associated with climate change model projections and its importance or acceptability to the wider audience. In other words, previous studies have not fully bridged the gap between uncertainties and communicating the results to inform on planning, adaptation and mitigation strategies. Therefore, it is essential for future studies focusing on the impact of CV&C on energy system to better communicate issues related to uncertainties in climate projections and improve the communication of results to the global audience. Addressing these research gaps will further advance the literature, provide options to protect the future energy system and increase our knowledge on CV&C impacts on the energy system in the coming years.

2.5.5. Strengths and limitations of the systematic scoping review

This scoping review applied rigorous and transparent approach. It follows a protocol reviewed by the research team with expertise in literature synthesis and scoping reviews. A broad search of the literature was conducted using two electronic search databases and one internet search engine and snowball technique. Screening the articles and data characterisation forms were pretested by the reviewers, while the articles were independently reviewed by the reviewers who regularly met to resolve conflicts. To ensure consistency in the scoping review which was conducted in a systematic manner, the Endnote software was used to manage and account for all citations retrieved from various databases. An updated search was conducted in February 2019 to ensure inclusion of recent publications.

This scoping review has several limitations. First, the searches were limited to articles published in English, potentially resulting to language bias and exclude relevant studies published in other languages. Second, the CV&C are associated with terms such as temperature change and weather conditions, which may have excluded terms such as overheating, extreme weather and global warming. Third, the search engines used are multidisciplinary databases, but other databases may contain additional studies relevant to this review. Fourth, subject experts or researchers were not contacted for additional studies and studies from gray literature were not included.

Finally, scoping reviews are not meant to assess the quality of the literature assessed or in this study, the quality of the GCMs used for CV&C impact assessment. However, the eligibility criteria ensured that the studies included for the review applied projections from relevant GCMs used for CV&C impact assessment. Therefore, this scoping review provides a comprehensive overview on the impact of CV&C on the energy system at a regional and country scale, reporting more than 1,790 individual results from 153 studies out of 176 articles included for the review.

2.6. Conclusion

The impacts of CV&C on future energy system have received considerable attention over the past decades. This systematic scoping review collated and mapped evidence by identifying consistent pattern of impacts based on results from studies reviewed. The review show that the geographical distribution of studies has continued to expand across the world, as new methods of impact assessment have improved. Although this review identified robust pattern of CV&C impacts, there is areas requiring further research. There is need to improve the systematic or scoping review to better contextualise the results in terms of technological, economic and environmental aspect of CV&C impacts on the energy system. Technological research can examine the implication of CV&C on future energy system in terms of changes in energy demand pattern in relation to changes in energy supply mix (both fuel mix and technology switching). The cost dynamic implications which includes social cost, changes in sales revenue, investment cost of capacity expansion and cost-benefit analysis can be included in economic assessment. The environmental aspect should explore the changes in GHG emissions under future climatic conditions.

The findings from the review agree that temperature changes will have serious implications on the energy system which will lead to changes in energy demand and energy supply. On the demand side, each temperature rise is projected to increase peak energy demand by 0.45%-8.5% due to increase in AC use. This will result in an increase in expenditure for consumers and increase in GHGs from peaking power plants which are mostly fossil fuel based. On the supply side, climate impact had less impact on solar PV systems compared to other renewables. This implies that solar PV system are more resilient to in a world of increasing uncertainty and vulnerability of the energy system to CV&C impacts. Therefore, solar PV system will have an important role to play in mitigating GHG emissions and adapt the energy system to future climatic conditions.

Further, thermal power plant in most regions may experience a decline in production efficiency due to global warming which will decrease the availability of cooling water for thermal plant operation. On water availability, the hydropower plant may also experience either a shortfall in power output due to reduced rainfall (most part of Africa and Asia) or increased power production due to glacier melt in other regions (e.g. Northern Europe). However, the increase in glacier melt may result in flooding in countries located in Norther Europe which may not translate to increase in power production from hydropower stations. These changes in power supply and demand will lead to significant changes in the electricity market as power companies will have to make changes in generation capacity, transmission and distribution networks.

In countries with interconnected electricity markets, the impact of CV&C on fossil fuel power plant and increase energy demand may make a case for renewable energy technologies such as hydropower and solar which is projected to increase in some regions.

Where such scenario exists, the implication will be differences in power prices which will give an added incentive for power companies to invest in sustainable power generation system. Besides renewable energy technologies, CCS for thermal power plant has been another option for GHG reduction but its application have raised a lot of questions due to its high cost compare to renewables. Some studies are of the opinion that CCS technologies are solution of the past and no longer necessary in a real progressive view of the future sustainable energy system (Breyer et al., 2018, Pursiheimo et al., 2018, Teske et al., 2018).

A better option may be the application of carbon capture and use (CCU) which not only captures the CO_2 but can potentially be used in manufacturing process (e.g. material for road construction). However, it remains unclear how changes in these low carbon technology options will shape the future energy system in the coming years considering climate change conditions. This aspect is still lacking in the literature and require further investigation. Other important areas of research include examining the impact of extreme weather events on future energy infrastructure, cross sectorial impacts of interconnected sectors, impacts on thermal and renewable power plants from a wholistic view considering inter-seasonal variations.

Future impact assessment should integrate the impact of CV&C on supply and demand side while consider socioeconomic dynamics. The study can also be extended to include cross-sectoral linkages and back-loops in a complete climate system model. Finally, future studies should examine how different international climate agreements and climate instruments might alter the energy markets under future climate conditions. As the global climate is changing in a future that is highly uncertain, the energy system is should also evolve. Policymakers, utility operators and researchers will continue to examine the pattern of CV&C impacts and explore mitigation and adaptation options for the energy system. This review could inform and safeguard energy infrastructure against climate change, ensure security of energy supply and ensure appropriate adaptation measures.

Chapter 3: The Impact of Climate Change on Electricity Demand in Australia

The previous chapter reviewed the literature on CV&C impacts, the methodological approaches to CV&C impacts, summarised the body of evidence and identified research gaps. This chapter estimated seasonal short- and long-term electricity demand for Australia, and simulated future temperature sensitive electricity demand were discussed (Figure 3.1).

This chapter has been adapted into the manuscripts: Emodi, N. V., Chaiechi, T., & Alam Beg, A. R. (2018). The impact of climate change on electricity demand in Australia. *Energy & Environment*, 0958305X18776538.

Initially, this manuscript (chapter 3) was prepared as conference paper titled Emodi, N. V., Chaiechi, T., & Rabiul, B. A. B. M. (2017). The Impact of Climate Change on Residential Energy Demand: A Case Study of Australia. Paper presented at the 35th United States Association for Energy Economics/International Association for Energy Economics (USAEE/IAEE) North American Conference 2017: Riding the Energy Cycles. Houston, Texas, 12th – 15th November 2017.

A short version of this chapter is also published as a media article in Science Trends which is available online at https://sciencetrends.com/implication-of-global-warming-on-electricity-demand-in-australia.

The conference paper focused on the impact of climate change on the residential sector in New South Wales and Queensland but was improved after various comments from the conference participants and incorporated into chapter 3.

For this chapter, the location of weather stations, results of the unit roots and bounds test, and plots of CUSUM and CUSUMSQ are shown in Appendix 4; the model accuracy results are presented in Appendix 5; and future cooling and heating degree days, monthly peak demand and percentage changes in electricity demand are shown in Appendix 6.

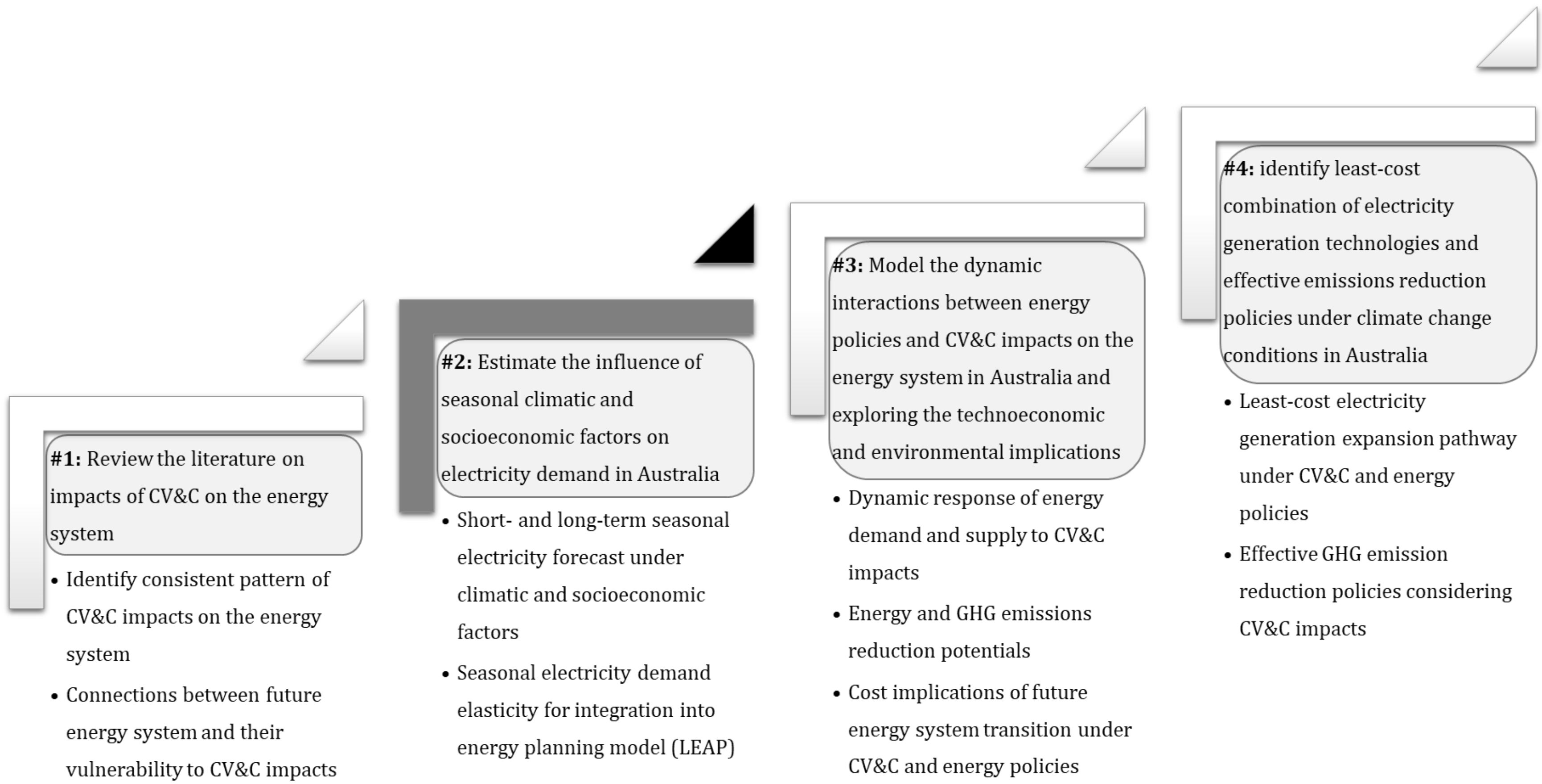

Figure 3. 1: Progress through the thesis: Research Aim #2.

3.1. Abstract

This study estimates the short- and long-term impacts of climate change on electricity demand in Australia. This study used an autoregressive distributed lag (ARDL) model with monthly data from 1999 to 2014 for six Australian states and one territory. The results reveal significant variations in electricity demand. The long-term coefficients were used for climatic response to simulate future electricity demand using four scenarios based on the representative concentration pathways (RCPs) of the Intergovernmental Panel on Climate Change (IPCC). Our results show a gradual increase in electricity consumption due to warmer temperatures with the possibility of peak demand in winter; however, demand tends to decrease in the middle of the twenty-first century across the RCPs, while the summer peak load increases by the end of the century. Finally, the impact of policy uncertainty was stimulated through sensitivity analysis and confirmed the potential benefits of climate change adaptation and mitigation.

3.2. Introduction

Global warming is an important aspect of climate change which is caused by the increased concentration of greenhouse gas (GHG) emissions in the atmosphere as a result of human activities (Wang et al., 2017). Global warming refers to the gradual increase in surface temperatures. This increase alters energy consumption because of changes in cooling and heating demand (Clarke et al., 2018). In temperate regions, studies show a paradigm shift towards an increased cooling demand while heating demand will gradually decrease by the end of the century (Parkpoom and Harrison, 2008). These findings imply that the demand for energy commodities used in cooling services such as electricity will increase and result in frequent peak demand. With regard to heating, consumers may switch to electricity, which is more efficient than conventional gas in the long-term. This change will result in seasonal peak demand for electricity, especially during the summer and winter months. Seasonal peak demand has in part been met by using fossil fuel for power plants. Such use is among the main contributors to climate change. The global effort to combat climate change may result in the closure of fossil fuel power plants in favour of renewable energy and low carbon technologies. However, intermittency and integration issues currently affect renewable energy technologies because battery storage is still in the early stages of development.

As consumption increases because of the rising demand for thermal comfort, the degree of consumers' expenditure remains uncertain, despite the adaptation policies in place to combat climate change (Véliz et al., 2017). Compounding the problem further is the issue of regional and state-level electricity consumption, which presents some challenges to interconnected electricity markets and dispatch operations. Globally, these challenges are mainly attributed to the differences in climatic patterns across regions and states (Shaik and Yeboah, 2018, Pilli-Sihvola et al., 2010). In some extreme cases, these patterns exhibit heatwaves (Burillo et al., 2017). Heatwaves, which are a result of excessively hot weather, have led to an increase in state-wide power blackouts in the United States[15], most countries in the European Union[16] (EU), and Australia,[17] among others. In Australia, the recent disruption in power supply in some states within the National Electricity Market, such as the blackouts in Victoria (VIC), were due to the prolonged and intensive heat, during which households used air conditioners (ACs) for prolonged periods, thereby exerting pressure on the power network, which had to close because of a circuit overload.[18] Further, heatwaves have led to shortfalls in the electricity supplies of the Australian Capital Territory (ACT), New South Wales (NSW), and South Australia (SA) in recent times.[19]

Electricity demand at the state level is unique and influenced by seasonal climatic and socio-economic conditions. Because of the differences in regional electricity demand, it is necessary to estimate the impact of climate change on state-level electricity demand. It is also important to identify the monthly peak load periods which can be induced by climatic conditions. Such identification helps power companies with planning and power dispatch operations, and consumers to know how their consumption pattern is likely to change in the coming years. Although studies (Pilli-Sihvola et al., 2010, Ahmed et al., 2012, Kaufmann et

[15] See http://assets.climatecentral.org/pdfs/PowerOutages.pdf
[16] See http://www.abc.net.au/news/2015-07-02/europe-feels-the-heat/6588854
[17] See https://www.reuters.com/article/us-australia-electricity-outages/australia-heat-wave-causes-firms-to-power-down-but-blackouts-avoided-idUSKBN15P0NZ
[18] See http://www.theage.com.au/victoria/sunday-blackouts-a-failure-of-electricity-networks-not-lack-of-supply-20180129-h0pvhx.html
[19] See https://www.theguardian.com/australia-news/live/2017/feb/10/australia-weather-heat-power-outage-blackout-fire-danger-nsw-live

al., 2013, Li et al., 2014, Fan et al., 2015, Chatzizacharia et al., 2016, Véliz et al., 2017) have examined the impact of climate change on electricity demand using regression models, there are shortcomings. These include the stationarity issue, which has not received much attention in the literature on climate change impact.

A regression model used in electricity demand forecasting may be biased if the stationarity properties are not tested because these may lead to spurious regression problems. Further, short- and long-term seasonal elasticities are important components of electricity demand planning and can be used effectively in demand forecasting; however, the literature has not considered this issue comprehensively. Moreover, the literature has not accounted for policy uncertainties such as technological disruption, market reforms, and adaptation strategies in detail (Chandramowli and Felder, 2014). These omissions are explained further in the current study's literature review section. This current study intends to address the aforementioned shortcomings by investigating the short- and long-term impacts of climate change on electricity demand in Australia using the autoregressive distributed lag (ARDL) model.

Australia was selected because of the frequent power blackouts in its states which are attributed to increasing temperatures, a high reliance on coal for electricity generation (about 54% of total generation), and the status of coal as the largest export earner (A$54 billion in 2008/09).[20] The use of coal makes Australia the worst CO_2 emitter per capita among developed countries (as highlighted by the executive secretary of the UN's Framework Convention on Climate Change).[21][22] However, the Australian government has set a renewable energy target (RET) of 33,000 GWh, or 23% of total power generation, by 2020 to be implemented at state level.

Finally, the differences in seasonal electricity consumption patterns require the generation of seasonal demand elasticities in order to understand consumers' responses to climate change more clearly, predict the cost of climate change, and develop a better adaptation strategy. The ARDL model was applied because of the stationarity properties of

[20] See http://www.minerals.org.au/resources/coal/coal_the_community/contribution_to_the_economy
[21] See http://www.abc.net.au/news/2015-05-06/un-climate-negotiator-urges-australia-to-take-leadership-role/6448802
[22] See https://www.theguardian.com/environment/2013/nov/19/australia-worst-carbon-emitter-per-capita-among-major-western-nations

the data sets. Further, a simulation was developed to estimate the influence of future temperature changes on electricity demand using four scenarios based on the representative concentration pathways (RCPs) of the Intergovernmental Panel on Climate Change (IPCC). Finally, a policy uncertainty assessment was conducted to examine the sensitivity of the demand forecasts to changes in policies such as energy efficiency improvements, renewable energy technology, and changes in electricity prices.

Our results show a gradual increase in electricity consumption because of warmer temperatures across the six states and one territory with the possibility of winter peaking, which is somewhat higher than summer peaking and tends to decrease mid-century across the RCPs. This study also discovered the potential benefits of climate change adaptation and mitigation for the RCP scenarios. The rest of this study is arranged as follows. Section 3.2 presents the literature review and this study's contributions. Section 3.3 describes the methodological approach, which includes the data, a unit root test, and the model which is applied. Section 3.4 presents the results and analysis, including the residual and diagnostic test, the model's accuracy, and simulations. Section 3.5 concludes the study.

3.3. Literature Review and Contributions

3.3.1. Literature Review

The literature on the climate change impact on energy demand has increased over the years. Early studies, such as those of Bhartendu and Cohen (1987) for Ontario in Canada, Pardo et al. (2002) for Spain, and Sailor and Pavlova (2003) for the US, applied a temperature function of cooling degree day (CDD) and heating degree day (HDD) in a regression model to estimate climate-induced impact on electricity demand. Their studies showed that heating demand will decrease, while cooling demand will gradually increase by mid-century because of rising temperatures. These trends will decrease natural gas and oil use, but increase electricity consumption. Applying socio-economic parameters as independent variables, Amato et al. (2005) and Ruth and Lin (2006) showed that a slight change in the price of energy may alter a demand response; moreover, such an alteration may be useful for reversing a climate-induced increase in energy demand.

Asadoorian et al. (2008) used regression models to estimate climatic feedback regarding electricity demand. Their results showed that income and price parameters were significant determinants of temperature-induced electricity demand in urban areas within China. However, the variability of weather conditions in the context of changing energy prices may lead to increased economic expenditure in the form of electricity consumption Mirasgedis et al. (2006). In a progressive study, Mirasgedis et al. (2007) estimated that economic growth may have a strong effect on increasing heating and cooling demand, which will in turn increase installed capacity; however, a larger percentage may be underutilized. The reason for underutilized capacity is because a significant part of installed capacity will be operational during peak loads in the summer, a situation which may increase the payback period of the corresponding units. Thus, supplementary adaptation policies need to be provided to ensure the security of supply to meet growing demand.

In the US, Mansur et al. (2008) found that a temperature increase of 5°C may result in economic damage of US$35 billion and US$22 billion in the residential and commercial sectors respectively by 2100. Further, Pilli-Sihvola et al. (2010) showed that countries in Central and Northern Europe will experience decreasing temperatures because of global warming, while Southern Europe will experience increasing climate warming, leading to increased costs from electricity consumption. In the same way that climate-induced electricity demand shows variations between urban and rural areas and between regions, variations exist within sectors. Kaufmann et al. (2013) investigated the weather effect on energy consumption in Massachusetts. Their results showed that the temperature of tap water is affected by climate change. Hence, in warmer temperatures, hot water tanks may use less energy to produce hot water. Li et al. (2014) and Fan et al. (2015) found that electricity consumption in the residential sector and tertiary industry is more sensitive to temperature changes than in the primary and secondary industries. The reason is that the main actors in the residential sector (humans) require constant thermal comfort, which increases electricity demand for space conditioning (Ürge-Vorsatz et al., 2015).

In order to reduce demand for space conditioning, Rhodes et al. (2016) applied a mixed effect regression model to estimate the effect of energy retrofits for 500 homes in Austin, Texas. The results illustrated the potential energy savings associated with attic insulation and replacing heating, ventilation, and air conditioning (HAVC) and duct systems. Similarly, the results of the regression model of Auffhammer et al. (2017) for the RCP 4.5 and RCP 8.5 scenarios suggested that without improved energy savings to reduce peak electricity demand due to space conditioning, significant increases in the intensity and frequency of peak events may occur in the US. More specifically, regional climate change may lead to frequent peaks which may require additional generation or storage capacity and new transmission networks. Damm et al. (2017) analysed the impact of 2^{o}C global warming on electricity demand in 26 European countries using the RCP 2.6, RCP 4.5, and RCP 8.5 scenarios and a smooth transition regression model. The results showed that 2^{o}C global warming will result in a decrease in electricity demand in most European countries. However, Italy will experience increased demand of between 0.2% and 0.6%, translating to 40 GWh over the reference period.

An increasing number of studies on seasonal climate forecasts of electricity demand have been conducted. For example, Ahmed et al. (2012) examined the impact of climate change on seasonal electricity demand. The study used a multiple linear regression (MLR) model with a percentage error of +1.97% to -3.09% and an average value of 0.34%. The results showed that electricity demand in NSW in Australia has increased during the summer and spring because of climate change. Similarly, De Felice et al. (2015) used linear and non-linear approaches to forecast seasonal electricity demand in Italy and Central Europe. They found increasing demand during the summer. The mean absolute percentage error (MAPE) of the linear model was 1.6% and 1.9% for May and April respectively, while the MAPE of the non-linear model (support vector regression) was 1.6% and 1.7% for May and April respectively. The results of the structural equation model of Burillo et al. (2017) suggested that an electricity demand forecast which does not consider climatic non-stationarity may have an inherent bias.

Spandagos and Ng (2017) applied an equivalent full load hours method to estimate the impact of climate change on building cooling and heating energy consumption in Hong

Kong, Seoul, and Tokyo using the RCP 4.5 and RCP 8.5 scenarios. The results showed that in the RCP 4.5 scenario, heating and cooling in residential households will increase by 18.3%, 4%, and 10.4% in Hong Kong, Seoul, and Tokyo respectively by 2044. In the RCP 8.5 scenario, the increases will be 23.3%, 9.3%, and 15.8% respectively. Shaik and Yeboah (2018) estimated the influence of climate on regional energy demand in the US using a seemingly unrelated regressions (SUR) model. The results demonstrated that the residential and industrial sectors are affected by temperature variations.

3.3.2. The Study's Contributions

Although the knowledge frontier regarding the climate change impact on electricity demand has advanced in recent years, there are some gaps in the literature as follows.

Stationarity of the socio-economic data sets used in multiple regression models. Most studies investigating the climate change impact on electricity demand have ignored the importance of the stationarity of their data sets (Chatzizacharia et al., 2016). Most importantly, macroeconomic data such as price, economic output or income, and population have been disregarded. Kumar Narayan and Smyth (2007) examined the stationarity properties of per capita energy consumption for 182 countries using the augmented Dickey–Fuller (ADF) unit root test. Their results rejected the unit root of 56 countries at the 10% level. They concluded that the stationarity of energy consumption has important implications for economic policies. This is because the non-stationarity of energy consumption variables could spread to other key macroeconomic variables, which may inherit the non-stationarity nature of the energy consumption variables in the case of an economic shock (Hendry and Juselius, 2001). This situation has prompted some studies to investigate a single country or panel of countries and to conduct analyses and literature reviews on the stationarity of the energy consumption variable (Kumar Narayan et al., 2010, Smyth, 2013, Wang et al., 2016b, Dogan, 2016). The regression model used in forecasting may be biased if the stationarity properties are not tested and thereby lead to spurious regression problems (Granger and Newbold, 1974, Pesaran and Shin, 1998).

Short- and long-term seasonal electricity forecasts. The short- and long-term determinants of electricity demand have been well researched in the literature (Fullerton Jr et al., 2012, Fullerton et al., 2015, Tatli, 2017, Campbell, 2018). Seasonal electricity forecasts have also been well researched, with approaches varying from linear to non-linear regression models. However, short- and long-term seasonal socio-economic changes and consumers' responses have not been well documented. For example, Fan and Hyndman (Fan and Hyndman, 2011, Fan and Hyndman, 2014) showed that electricity consumers in SA respond more to changes in electricity prices during the winter months than the summer months. Further, an energy commodity such as electricity yields utility to consumers through household appliances and industrial equipment (King and Weimer, 2000). Thus, the seasonal effect will alter consumers' short- and long-term elasticity of demand for electricity. Ahmed et al. (2012) used a split sample regression approach to estimate the seasonal elasticity of electricity demand in NSW; however, the short- and long-term elasticities of socio-economic and climatic parameters were not estimated. Short- and long-term elasticities are important for utility companies and policymakers in order to determine consumers' responses to electricity demand in different seasons.

Accounting for uncertainties in electricity demand forecasting under climate change conditions in relation to energy efficiency improvement, renewable energy adoption, and electricity price volatility. Climate change will no doubt affect energy consumption patterns through changes in heating and cooling loads in buildings. This effect will result in changes in the fuel mix, with an increase in electricity use for cooling and a decrease in heating with natural gas or fuel oil. The changes will also alter consumers' expenditure because they will maintain thermal comfort in buildings and commercial establishments. Studies have focused on the cost implications due to changing climatic conditions (Clarke et al., 2018). Such cost implications have been attributed to increases in electricity prices (Véliz et al., 2017). Electricity prices are volatile; moreover, for many years, the electricity market has been dominated by conventional generation plants which have been controllable. However, renewable energy, which is intermittent in nature, has created a change in the electricity market because it is based not on demand but on the availability of resources such as the sun and wind (Märkle-Huß et al., 2018). Renewable energy has an important role to play in climate change adaptation, mitigation, and sustainable development (Ley, 2017, Mitigation, 2011). Thus, it is important to examine the advent of new technologies with improved energy efficiency for cooling and heating because these may alter electricity demand forecasts. Consumers' responses to electricity price changes under climate change conditions have also not been well researched in the literature. Aroonruengsawat and Auffhammer (Aroonruengsawat and Auffhammer, 2011) simulated price changes under changing climatic conditions in California and assumed a discrete 30% increase from 2020. However, renewable energy has the potential to lower electricity prices and bills for households and businesses (Trading, 2014, Agency, 2015). Further, the cost of solar photovoltaic (PV) installations is projected to decrease by 25% by 2020, 45% by 2030, and 65% by 2050.[23] Thus, energy savings from renewables, energy efficiency improvements, and price volatility need to be considered in electricity demand forecasting.

The generation of seasonal electricity demand elasticities for integration into energy planning tools such as the market allocation (MARKAL) and long-range energy alternatives planning (LEAP) models. While these models account for changes in future technologies, socio-economic conditions, and policy impacts, they are not able to adequately incorporate the uncertainties associated with shifts in end-use energy demand due to climatic variability and change (Chandramowli and Felder, 2014, Mukherjee and Nateghi, 2017). The estimates for electricity demand elasticity and climate change scenario predictions can be fed into energy planning tools such as LEAP, MARKAL, and other similar tools for scenario planning (Nateghi and Mukherjee, 2017). Thus, seasonal electricity demand elasticity will be useful in an energy planning model to account for consumers' responses to seasonal climatic conditions in the short and long terms.

This current study intends to address the foregoing gaps in the literature by applying an ARDL model, which considers the stationarity of the data sets, with the data divided into four seasons to estimate and forecast short- and long-term seasonal electricity demand. Finally, the demand elasticities are used to forecast electricity demand under climate change

[23] See
https://www.iea.org/media/freepublications/technologyroadmaps/solar/TechnologyRoadmapSolarPhotovoltaicEnergy_2014
edition_foldout.pdf7.pdf

conditions, which are further simulated to account for changes in economic growth, energy efficiency, renewable energy adaptation, and changes in electricity prices.

3.4. Methodological Approach

3.4.1. Overview

The methodological approach used to investigate the impact of climate change on electricity demand in this study is presented in Figure 3.2.

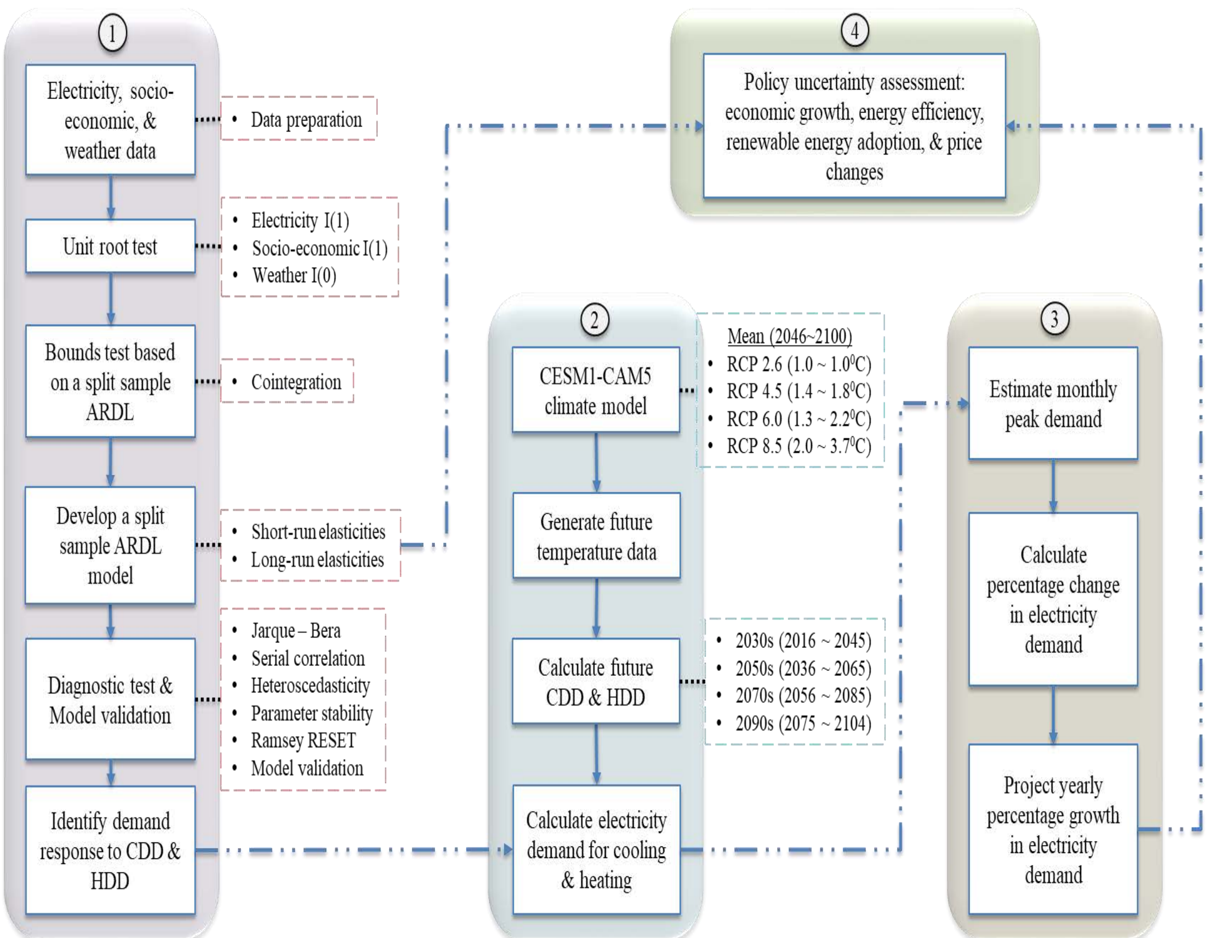

Figure 3. 2: Methodological approach.

The first step used the following types of data: i) with regard to electricity demand, socio-economic data, including gross state product (GSP), population, and electricity price; ii) with regard to the weather, a data set with maximum and minimum temperature data converted into CDDs and HDDs. Two unit root tests were conducted to ascertain the stationarity of the data sets. The results showed that the variables were integrated with mixed orders of $I(0)$ and $I(1)$. Thus, following Pesaran et al. (2001), the ARDL model was used to estimate the long-term relationship between the variables. The data sets were divided into the four seasons of summer, autumn, winter, and spring. The split-sample approach to the ARDL model ensured that statistical issues, such as serial correlation and heteroscedasticity, were avoided. It is important to note that energy consumption between seasons is heterogeneous. However, the model applied in this study captured energy consumption within seasons; hence, the model is homogeneous.

A Pesaran bounds F-test was conducted to estimate the existence of co-integration relationships among the variables. After co-integration was established, the split-sample ARDL model was estimated for each state in Australia for the short- and long-term coefficients. This was followed by a diagnostic test and model validation of the ARDL model. In the second stage, future temperature data sets were generated from global climatic models (GCMs) using four IPCC RCP scenarios. The future temperatures were converted to CDDs and HDDs for four time periods: the 2030s, 2050s, 2070s, and 2090s. In the third stage, electricity demand for cooling and heating in the future periods was calculated by multiplying the long-term coefficients from the ARDL model by the future CDDs and HDDs. The monthly peak demand and percentage changes were estimated in the third stage. The yearly percentage growth in electricity demand was projected under climate change conditions. In the final phase, long-term elasticities from the ARDL model and the projected electricity demand were used for a policy uncertainty assessment.

3.4.2. Data Sources and Preparation

The historical electricity demand and price data for the states of NSW, VIC, Queensland (QLD), SA, and Tasmania (TAS) were retrieved from the Australian Energy

Market Operator (AEMO) website (Operator, 2017c). Data for Western Australia (WA) were retrieved from the AEMO Western Australia website (Operator, 2017b). The available data were for July 2008 to 2017. The Northern Territory (NT) had data sets from mid-2015 to 2017, which were available from the Interim Northern Territory Electricity Market (I-NTEM) website (Market, 2017). The electricity demand data include demand from the agricultural, commercial, industrial, and residential sectors.

The socio-economic data, which include GSP (in real Australian dollars (AUD)) and the population, were retrieved from the Australian Bureau of Statistics (Statistics, 2016c). The population data were in a quarterly format and converted to monthly data sets using quadratic low to high frequencies. The population growth rate was used in the final analysis. The GSP is annual data. Each GSP was kept constant throughout the time periods. Because most time periods covered the 2008 recession, the monthly data sets were thoroughly inspected. No breaks or drops were observed. Moreover, the Australian economy was more resilient and experienced fewer effects from the financial crisis than other countries (Australia, 2010b).

The CDDs and HDDs were calculated using historical temperature data from the weather stations for each state, as shown in Table A4.1 of Appendix 4. The data were obtained from the Bureau of Meteorology (BOM) (Meteorology, 2017). The base temperatures used were based on the annual and monthly degree-day calculations from the BOM, which were 12–18˚C for HDDs and 18–24˚C for CDDs. Because of the availability of relevant data sets, monthly time series data sets from January 1990 to December 2016 were used for NSW, VIC, QLD, and SA. January 2007 to December 2016 was used for WA, January 2006 to December 2016 for TAS, and January to December 2016 for NT.

Monthly time-series data are preferred in climate–energy studies because they generate more robust estimates of the climate–energy relationship than annual or quarterly time-series data. The reason is that there are more observations and variability between observations (Amato et al., 2005). The data associated with each variable were grouped into four seasons in a split-sample format for summer, autumn, winter, and spring. This ensured that the seasonal relationships between the climate–energy socio-economic variables were estimated to identify the seasonal pattern. EVIEWS statistical software, which is widely used by economists, was used for the data preparation and analysis.

3.4.3. Selection of the Variables

Prior to unit root testing, it is necessary to identify the important variables which influence electricity consumption. Such identification ensures less data-processing time. There are two types of electricity consumption in a building: *baseload* and *weather-dependent consumption*. However, the literature suggests that there is a higher proportion of *weather-dependent consumption* compared with *baseload consumption* (Agrawala et al., 2011, Mirasgedis et al., 2007). Further, *baseload consumption* may remain constant throughout the year because consumers may not change their appliance stock; however, variations in temperature have a significant impact on electricity consumption (Chen et al., 2016).

Measuring the influence of *temperature changes* on electricity demand can be calculated through the degree-day methods described in Equations 3.4 – 3.7 in Section 3.3.5. This method has been widely applied in literature which focuses on the impact of climate change on energy demand (Pilli-Sihvola et al., 2010, Rhodes et al., 2016, Mima and Criqui, 2015b, Ruth and Lin, 2006, Sailor and Pavlova, 2003). Other weather variables, such as *relative humidity* and *wind speed*, were excluded from the final model because they were insignificant. Further, *solar exposure* was correlated with *CDD*, while *precipitation* was correlated with *HDD*. Such studies as Mansur et al. (2008) and Fan et al. (2015) have suggested that *precipitation* has no significant impact on energy consumption.

Socio-economic variables, such as *population*, are important indicators which are used to estimate an increase or decrease in energy consumption. The reason is that if per capita energy consumption remains constant over time, total energy consumption would change in accordance with a change in population (Ahmed et al., 2012). In terms of *income* at a sectorial level, studies have shown that income is positively elastic with regard to energy consumption and that a change in income is associated with an increase in energy consumption, implying that energy is treated as a normal good (Fullerton et al., 2015, Gertler et al., 2011). At state level, Ahmed et al. (2012) showed that *GSP* has a seasonal influence on electricity demand, except during spring. At national level, numerous studies have identified the existence of co-integration between *gross domestic product* (*GDP*) and energy consumption (Faisal et al., 2016, Ozturk et al., 2010, Wang et al., 2016a). Since this study is focused on state-level electricity demand, *GSP* is used to account for the influence of economic activity on energy demand.

With regard to short- and long-term dynamics, Fullerton Jr et al. (2012) suggested that energy demand is a normal good in the short term but an inferior good in the long term. *Price* is an important indicator in the assessment of energy demand because its elasticities affect electricity and energy policies in general (Labandeira et al., 2017). Alberini et al. (2011) found that energy prices have a strong influence on residential households in the US because an increase in price is associated with the use of less energy-intensive appliances. Jamil and Ahmad (2011) showed that aggregate electricity demand and electricity *price* have a long-term relationship and that electricity demand is price elastic. The aforementioned studies justify the inclusion of the selected variables, which are *GSP*, *population*, *price*, *CDD*, and *HDD*, in the ARDL model as major determinants of electricity demand in Australia.

3.4.4. Unit Root Test

In econometrics, time-series data sets are assumed to have some form of stationarity, whereby the mean and covariance of the variable may depend on the time gap. However, most macroeconomic data sets are integrated; thus time-series regression with such variables at their levels can yield spurious results (Granger and Newbold, 1974, Stock and Watson, 1988). In order to avoid spurious regression results and identify the appropriate model specification, the variables need to be tested for stationarity to determine if their mean and covariance values do not depend on the time gap. A stationarity or unit root test determines whether the data are trending over time and require differencing.

Two stationarity tests were applied in this study: the ADF (Dickey and Fuller, 1979) and the Kwiatkowski–Phillips–Schmidt–Shin (KPSS) (Kwiatkowski et al., 1992) tests. The null hypothesis of the ADF test suggests the presence of non-stationarity, while the null hypothesis of the KPSS test suggests the presence of no stationarity of the series. The results of the ADF and KPSS tests for the levels and first differences of the variables in each state, with and without time trends, are presented in Table A4.2 of Appendix 4. The results suggest that most of the *electricity demand*, *GSP*, and *population* variables are integrated at order one or $I(1)$, which requires first differencing, while *electricity price* and most climatic variables (*CDD* and *HDD*) are stationary at their levels.

3.4.5. Autoregressive Distributed Lag Model

Because of the order of integration of the variables at their levels and the first differences, the next step is to test for a co-integrating relationship among the variables using an ARDL model. Testing for a co-integrating relationship can be conducted with traditional methods, such as those of Engle and Granger (1987) and Johansen (1991), Johansen (1995), if the variables are all the same order of integration. If the variables are all stationary (i.e. $I(0)$), the model can be estimated with an ordinary least squares estimation; however, if the variables are all non-stationary (i.e. $I(1)$), a vector error correction model (with the Johansen approach) can be applied only if the $I(1)$ variables are co-integrated. These methods require the dependent and independent variables to be in either $I(1)$ or $I(0)$; however, this study's variables are integrated with a mixed order of $I(1)$ and $I(0)$. In order to estimate the variables, the ARDL bounds test for co-integration was applied.

According to Pesaran and Shin (1998), the ARDL model is capable of estimating co-integrating relationships with variables of a mixed integrated order of $I(1)$ and $I(0)$ without the need to pre-specify the orders. However, it is essential to test for $I(\mathrm{d})$, because the Pesaran test (Pesaran et al., 2001) is invalid if the order of integration is more than 1. The F-test is developed only for the $I(0)$ and $I(1)$ mix. Further, the ARDL model does not require symmetry of lag lengths, which means that the variables can have various lag terms within the ARDL model. The ARDL model is a standard least squares regression, which includes lags of dependent and independent variables as regressors together with the levels of the independent variables. In order to estimate the ARDL model, the following has to be satisfied: i) the dependent variable must be non-stationary, which is differenced; ii) none of the variables should be in the second order or $I(2)$ in normal conditions under the ADF unit root test; and iii) one of the independent variables must be fixed or static (with no lagged term) while others must be dynamic (with at least one lagged term). The lag length is then specified for the model with either the Akaike, Schwarz, or Hannan–Quinn information criteria.

The post-estimation diagnostic began with the long-term transformation of the ARDL model in order to examine the long-term response of the dependent variable to the change in the independent variables. The next step examined the co-integrating relationship by transforming the variables into first differences in the ARDL model and substituting the long-term coefficients. Finally, the bounds-testing approach suggested by (Pesaran et al., 2001) was implemented using the co-integrating relationship to test if the ARDL model has a level or long-term relationship between the independent variables and regressors. The bounds test was based on the joint F-statistic, whose asymptotic distribution is non-standard under the null hypothesis of no level relationship or co-integration (defined by H_0: $n_1 = n_2 = n_3 \ldots n_k = 0$). The F-statistics were compared with the bounds values provided in Pesaran et al. (Pesaran et al., 2001) for all orders of the regressors (i.e. $I(1)$ or $I(0)$). The null hypothesis was accepted when the F-statistics were below the lower bounds values, inconclusive when they were around the centre, and rejected when they were higher than the upper bounds values. The null and alternative hypotheses which were tested are as follows.

$$H_0: n_1 = n_2 = n_3 = \cdots = n_5 = 0 \ (no\ level\ relationship) \qquad Eq. (3.1)$$

$$H_1: n_1 \neq n_2 \neq n_3 \neq \cdots \neq n_5 \neq 0 \ (level\ relationship\ exists) \qquad Eq. (3.2)$$

Based on the justification for the selection of the variables, the proposed seasonal model takes the following form:

$$\log EL_{st} = a_0 + \underbrace{a_1}_{(+)} \log GSP_{st} + \underbrace{a_2}_{(+)} POP_{st} + \underbrace{a_3}_{(-)} PR_{st} + \underbrace{a_4}_{(+)} CDD_{st} + \underbrace{a_5}_{(-)} HDD_{st} + \varepsilon_t \qquad Eq. (3.3)$$

Here, s represents the state (NSW, VIC, QLD, SA, WA, TAS, and NT) at time period t. *log* represents the natural logs of the variables in Equation (3.3). $\log EL_{st}$ represents the log of electricity demand for state s at time t. $\log GSP_{st}$ represents the log of GSP for state s at time t. POP_{st} is the population growth rate for state s at time t. PR_{st} represents the price of electricity for state s at time t. CDD_{st} and HDD_{st} are CDD and HDD respectively for state s at *time* t. ε_t is the error term, while a_0, a_1, a_2, a_3, a_4, and a_5 are the elasticities to be estimated. The signs in parentheses represent the expected behaviour for the independent variables. The degree-day variables, which are the difference between the outdoor and base temperatures required for cooling or heating, are calculated using the base and average temperatures. The CDD is calculated as follows.

$$CDD = \sum_{i=1}^{N_m} \delta_{im1} \left(T_{im} - T_b\right) \qquad Eq. (3.4)$$

where N_m is the number of the days in month m, T_{im} is the average air temperature of day i in month m, T_b is the base temperature, and δ_{im1} is a binary variable which takes the following form:

$$\delta_{im1} = \begin{cases} 1 & if\ T_{im} - T_b \geq 0 \\ 0 & if\ T_{im} - T_b < 0 \end{cases} \qquad Eq. (3.5)$$

The HDD is calculated as follows.

$$HDD = \sum_{i=1}^{N_m} \delta_{im2} \left(T_b - T_{im}\right) \qquad Eq. (3.6)$$

where N_m is the number of days in month m, T_{im} is the average air temperature of day i in month m, T_b is the base temperature, and δ_{im1} is a binary variable which takes the following form:

$$\delta_{im2} = \begin{cases} 1 & if\ T_b - T_{im} \geq 0 \\ 0 & if\ T_b - T_{im} < 0 \end{cases} \qquad Eq. (3.7)$$

A state's GSP, measured in AUD, is expected to increase as electricity consumption rises across the state; however, it may vary in the different seasons under observation. This assumption follows economic theory in which electricity consumption is considered a normal good and the demand elasticity for GDP is expected to be positive (Gam and Rejeb, 2012, Krizanic and Oplotnik, 2005). From a household's perspective, energy commodities are a necessity because they ensure that basic needs can be met. However, in metropolitan areas, energy is treated as an inferior good in the long term but a normal good in the short term (Fullerton Jr et al., 2012, Wang et al., 2016a). From an income perspective, energy commodities are a normal good for low-income households and an inferior good for high-income households (Meier et al., 2012).

Seasonal growth in population is expected to increase a state's electricity demand. The growth in population also includes births and migration each month. A decrease in population growth is expected to be associated with a reduction in electricity demand. The CDD and HDD hypothesis is based on the assumption that the cooling requirement will be higher during the summer and that the global rise in temperatures will result in a decrease in heating requirements (Al-Obaidi et al., 2014, Li et al., 2012b). However, colder regions of the world are expected to have a considerable increase in heating loads (Kikumoto et al., 2015). Although the model does not directly capture the influence of retrofitted buildings, which may influence seasonal consumption patterns (Rhodes et al., 2016), this influence is expected to be observed through changes in GSP.

In accordance with economic theory, a price increase is associated with a decrease in energy demand (Platchkov and Pollitt, 2011, Sorrell, 2015, Stern, 2004). Accordingly, the price coefficients measure how consumers adjust electricity consumption because of changes in price by adjusting their consumption behaviour (Fan and Hyndman, 2011). Thus, price elasticity is expected to be negative and larger in the long term than in the short term because learning about, and responding to, changes in the electricity price will probably take some time. The ARDL model applied in this study is for all four seasons and is as follows.

$$\begin{aligned}\Delta \log(EL_t) = a_0 + \sum_{i=1}^{p} a_i \Delta \log(EL_{t-1}) + \sum_{i=0}^{q_1} b_i \, \Delta \log(GSP_{t-1}) \sum_{i=0}^{q_2} c_i \Delta POP_{t-1} + \sum_{i=0}^{q_3} d_i \Delta PR_{t-1} \\ + \sum_{i=0}^{q_4} e_i \Delta CDD_{t-1} + \sum_{i=0}^{q_5} f_i \Delta HDD_{t-1} + \lambda_1 \log GSP_{st-1} + \lambda_2 POP_{st-1} + \lambda_3 PR_{st-1} \\ + \lambda_4 CDD_{st-1} + \lambda_5 HDD_{st-1} + \varepsilon_t \qquad Eq.(3.8)\end{aligned}$$

where all variables are as previously defined and $a_i, b_i, c_i, d_i, e_i, f_i$, and g_i are the short-term dynamic coefficients of the underlying ARDL model. The lag orders of the ARDL (p, q_1, q_2, q_3, q_4, and q_5) model in the six variables were selected using the Akaike information criterion. The monthly data sets were analysed for four seasons: summer (December–February); autumn (March–May); winter (June–August); and spring (September–November). Because NSW, VIC, QLD, and SA had monthly data sets for January 1999 to December 2016, each model estimation for a particular season contained 75 observations per variable. WA, TAS, and NT respectively had 30, 33, and 92 seasonal observations per variable for the model estimation. It is noteworthy that during the process of the bound F-test, each variable was considered a dependent variable in the ARDL regression model; however, the results for only the level relationship and the existence of co-integration are reported in Table A4.3 of Appendix 4. From the results of the bounds test using the F-statistics, it is clear that co-integration exists between the variables presented in Equation (3.8) and that the null hypothesis of no level relationship is rejected.

3.4.6. Estimating Future Electricity Demand

The main aim of this study is to estimate the short- and long-term impacts of temperature changes due to climate change on electricity demand. However, the analysis was extended to investigate the impact of future temperature changes due to climate change on electricity demand. The model applied in forecasting electricity demand followed the parametric MLR approach which Apadula et al. (2012) used in estimating electricity demand for the next month. The approach was preferred because of its simplicity and ability to capture the influences of socio-economic and climatic parameters in a monthly or seasonal order. The forecasting approach was based on the following assumptions.

- Estimated monthly electricity demand is based on the actual consumption of the prior month and considers changes in climatic and socio-economic factors which determine demand in the long term.

- Seasonal variation between subsequent months is accounted for by assuming that the ratio of electricity demand in these months is equal to the corresponding ratio estimated in the prior year.
- Seasonal changes in the short and long terms for climatic and socio-economic parameters are used as adjustment factors for estimated electricity demand.

Following Apadula et al. (2012), monthly demand, M, was estimated using the following relationship:

$$M_{m,y} = {(D_{m-1,y} \times D_{m,y-1})}\Big/{D_{m-1,y-1}} \qquad Eq. (3.9)$$

where D is the actual monthly demand, m and y represent the current month and year, and *m-1* and *y-1* represent the prior month and year. Changes in climatic, ΔC, and socio-economic, ΔEc, parameters are then accounted for by the following relationship:

$$\Delta(C, Ec) = \left[\Delta(C, Ec)_{m,y} - \Delta(C, Ec)_{m-1,y}\right] - \left[\Delta(C, Ec)_{m,y-1} - \Delta(C, Ec)_{m-1,y-1}\right] \quad Eq. (3.10)$$

where ΔC represents changes in climatic parameters such as CDD and HDD, while ΔEc refers to the changes in the socio-economic parameters used in this study such as population, GSP, and price. The estimated M and $\Delta(C, Ec)$ are used to forecast electricity demand for future time periods, F, as follows:

$$F_{m,y} = M_{m,y} \times (L_{ARDL}) \qquad Eq. (3.11)$$

where L_{ARDL} is the adjustment factor estimated using the least squares of the ARDL model, where the independent variable is $\Delta(C, Ec)$, which is expressed in Equation (3.10), and the dependent variable is Y. The dependent variable Y is as follows.

$$Y_{m,y} = 1 - \left({D_{m,y}}\Big/{M_{m,y}}\right) \qquad Eq. (3.12)$$

It is important to note that in the climate change impact simulation, the variables for socio-economic parameters were held constant at the base period, while the estimated electricity demand was based on projected temperatures retrieved from the GCM. In order to account for policy uncertainty in terms of economic growth and policy uncertainty, the respective seasonal elasticities for GSP and electricity price were used. This approach was applied in sections 3.44.

3.5. Results and Analysis

3.5.1. Results of the ARDL Model

The results which demonstrate the sensitivity of electricity demand to climatic and socio-economic variables in the short- and long-term are presented in Table 3.1. The estimated coefficients show that the response to lower temperatures is higher in southern states compared northern areas (NT and QLD). Most Australian households tend to use electricity for heating and cooling purposes through reverse cycle ACs (Statistics, 2014). The results for seasonal demand response to changes in weather patterns, as presented in Table 3.1, are similar to the results of the seasonal patterns in consumption reported in the report of the Australian Energy Regulator (AER) on electricity bill benchmarks for residential customers in Australia (except WA) (Regulator, 2015a).

The AER's results showed higher electricity use during winter for the states of NSW, ACT, VIC, and TAS. The peak demand during winter was attributed to an increase in heating demand except for QLD, whose demand is generally flat across the year, and NT, which has an HDD fall during winter. In such seasons as summer, a 1-unit change in HDD results in a decrease in electricity demand in the short and long term by, respectively, 0.58% and 0.38% in NSW, 0.28% and 0.17% in VIC, 0.34% and 0.21% in SA, and 0.84% and 0.70% in TAS. During winter months, changes in economic growth tend not to influence electricity demand during winter in VIC, QLD, WA, TAS, and NT; however, they have short- and long-term influences on electricity demand in SA and NSW. During summer months, a positive impact is observed in NSW, VIC, and QLD.

Table 3. 1: Short- and long-term coefficients using an ARDL bounds test for electricity (LogEL)

	Variables	New South Wales		Victoria		Queensland		South Australia		Western Australia		Tasmania		Northern Territory	
		Short-term	Long-term	Short-term	Long-term	Short-term	Long-term	Short-term	Long-term	Short-term	Long-term	Short-term	Long-term	Short-term	Long-term
Summer	*LogGSP*	1.81***	2.17***	2.10***	2.32***	1.33***	1.82***	1.03**	1.01**	1.42**	0.58	2.93**	2.21**	-2.17E-4	-2.35E-4
	POP	-23.42**	-20.97**	-23.13**	2.91	-27.01**	-31.46**	-16.04	-8.65	-23.74**	-15.90**	-0.27	-0.16	54.25	52.87
	PR	4.59E-4**	5.20E-4**	4.97E-4**	8.96E-4**	-5.81E-5	-3.98E-5	1.88E-4	1.01E-4	3.79E-4	2.54E-4	8.89E-4	7.56E-4	1.71E-3	4.58E-3***
	CDD	3.27E-3***	2.12E-3***	3.38E-3**	2.07E-3**	3.38E-3***	2.32E-3***	4.09E-3**	1.17E-2***	3.85E-3**	2.58E-3**	6.20E-3	3.63E-3	1.51E-2**	1.36E-2**
	HDD	-5.84E-3*	-3.79E-3*	-2.76E-3***	-1.70E-3**	-5.78E-3	3.96E-3	-3.84E-3**	-2.07E-3**	-8.72E-3	-9.50E-3	8.24E-3***	6.99E-3***	-4.39E-3	-2.59E-3
	Constant	-2.18E-2***		-3.31E-2***		-2.32E-2**		-1.43E-2*		-7.55E-3		-1.75E-2		0.53	
	ECT(-1)	-1.54***		-1.63***		-1.45***		-1.85***		-1.49***		-1.71***		-1.70***	
	R^2	0.75		0.90		0.72		0.88		0.89		0.76		0.51	
	Adj. R^2	0.69		0.83		0.67		0.84		0.84		0.66		0.40	
	S.E. of Reg.	0.03		0.02		0.04		0.04		0.03		0.04		0.04	
	SSR	0.04		0.02		0.07		0.05		0.02		0.04		0.05	
	F-stat.	13.84***		12.63***		13.91***		28.08***		19.17***		7.52***		3.91	
	D-W stat	2.41		1.80		1.64		2.15		1.65		2.04		2.01	
	J-Bera Test	x^2: 2.11 (Prob: 0.35)		x^2: 1.30 (Prob: 0.52)		x^2: 2.07 (Prob: 0.36)		x^2: 5.21 (Prob: 0.07)		x^2: 0.95 (Prob: 0.62)		x^2: 1.04 (Prob: 0.59)		x^2: 1.13 (Prob: 0.57)	
	B-G LM Test	x^2: 1.69 (Prob: 0.20)		x^2: 0.84 (Prob: 0.45)		x^2: 0.81 (Prob: 0.45)		x^2: 0.78 (Prob: 0.46)		x^2: 1.13 (Prob: 0.35)		x^2: 1.43 (Prob: 0.26)		x^2: 3.52 (Prob: 0.11)	
	BPG LM Test	x^2: 0.50 (Prob: 0.87)		x^2: 0.69 (Prob: 0.80)		x^2: 0.57 (Prob: 0.80)		x^2: 1.59 (Prob: 0.14)		x^2: 1.38 (Prob: 0.27)		x^2: 2.25 (Prob: 0.10)		x^2: 1.52 (Prob: 0.12)	
	Ramsey RESET	x^2: 5.71 (Prob: 0.22)		x^2: 0.77 (Prob: 0.39)		x^2: 6.69 (Prob: 0.13)		x^2: 0.11 (Prob: 0.75)		x^2: 1.04 (Prob: 0.32)		x^2: 4.98 (Prob: 0.37)		x^2: 0.10 (Prob: 0.78)	
Autumn	*LogGSP*	-0.37	-0.30	1.26**	0.94**	0.50**	0.42**	1.15**	0.44	-0.17	-0.10	-0.97	-0.80	-2.00E-4	-1.22E-4
	POP	-7.05	-2.25	-8.00**	-10.29*	-9.28	54.72**	-17.59	-29.17**	6.26	3.61	-28.42	-23.55	-55.29	-27.87
	PR	-4.96E-4**	-9.51E-4*	6.53E-4**	4.89E-4*	-9.16E-4***	-1.38E-3***	2.86E-4	1.91E-4	-5.23E-4	-6.08E-4	-4.84E-4**	-4.01E-4**	1.18E-3***	1.02E-3***
	CDD	2.38E-3**	1.93E-3**	6.86E-3**	1.14E-2***	2.32E-3***	1.00E-2***	9.10E-3***	6.09E-3***	6.92E-3***	8.93E-3***	5.55E-3	4.60E-3	1.97E-3**	7.72E-3***
	HDD	1.70E-3***	2.82E-3***	6.54E-3***	8.71E-3***	1.55E-3***	1.42E-3**	1.78E-3**	1.76E-3*	3.61E-3***	2.90E-3***	7.79E-3***	1.32E-2***	1.49E-3	1.45E-3
	Constant	3.48E-3		-8.52E-3		-1.09E-3		-5.11E-3		1.31E-2*		1.76E-3		0.48	
	ECT(-1)	-1.23***		-1.33***		-1.19***		-1.49***		-1.73***		-1.21***		-1.16***	
	R^2	0.95		0.85		0.98		0.90		0.97		0.72		0.40	
	Adj. R^2	0.93		0.82		0.96		0.88		0.96		0.64		0.38	
	S.E. of Reg.	0.02		0.03		0.01		0.03		0.02		0.06		0.05	
	SSR	0.01		0.04		0.01		0.04		0.01		0.08		0.04	
	F-stat.	58.05***		27.24***		70.13***		32.73***		74.93***		8.54***		4.43***	
	D-W stat	1.87		1.81		2.00		2.01		2.32		1.92		2.04	
	J-Bera Test	x^2: 9.73 (Prob: 0.01)		x^2: 1.42 (Prob: 0.49)		x^2: 2.20 (Prob: 0.33)		x^2: 1.32 (Prob: 0.52)		x^2: 8.67 (Prob: 0.01)		x^2: 0.14 (Prob: 0.93)		x^2: 1.15 (Prob: 0.56)	
	B-G LM Test	x^2: 0.14 (Prob: 0.87)		x^2: 2.55 (Prob: 0.10)		x^2: 0.04 (Prob: 0.96)		x^2: 0.38 (Prob: 0.69)		x^2: 2.77 (Prob: 0.10)		x^2: 1.44 (Prob: 0.26)		x^2: 3.79 (Prob: 0.10)	
	BPG LM Test	x^2: 0.57 (Prob: 0.86)		x^2: 2.64 (Prob: 0.02)		x^2: 0.34 (Prob: 0.99)		x^2: 0.73 (Prob: 0.70)		x^2: 1.13 (Prob: 0.39)		x^2: 3.18 (Prob: 0.16)		x^2: 0.84 (Prob: 0.60)	
	Ramsey RESET	x^2: 0.00 (Prob: 0.97)		x^2: 0.42 (Prob: 0.52)		x^2: 0.53 (Prob: 0.47)		x^2: 1.08 (Prob: 0.31)		x^2: 0.40 (Prob: 0.53)		x^2: 0.07 (Prob: 0.80)		x^2: 2.44 (Prob: 0.12)	
Winter	*LogGSP*	0.88	1.03**	0.27	0.21	0.06	0.08	0.78*	0.16	-0.01	-7.60E-3	3.41E-2	2.24E-2	-2.00E-4	-3.05E-4
	POP	-30.40**	-15.22	4.30	3.25	-9.73	-13.03	13.01	9,99	15.38**	9.79**	0.86	0.56	-55.29	-49.49
	PR	-1.44E-5	-8.42E-6	1.28E-4	9.66E-5	3.42E-5	4.58E-5	-4.45E-4**	-4.10E-4	-1.34E-4	-8.53E-5	1.46E-5	9.57E-5	1.23E-3***	1.10E-3***
	CDD	-1.06E-2	-6.19E-3	-3.77E-2***	-2.85E-2***	1.52E-2	2.03E-3	4.07E-2	3.41E-2	-1.17E-2	-7.42E-3	-9.45E-2**	-6.20E-2**	1.96E-3**	5.45E-3***

	HDD	5.19E-3**	1.23E-2***	3.05E-2***	2.31E-2***	2.43E-3**	3.25E-3**	2.52E-2***	3.12E-2**	1.35E-2***	8.58E-3***	3.82E-2***	2.50E-2***	1.48E-3	1.33E-3
	Constant	-1.07E-2		-1.99E-3		2.88E-3		-1.14E-3		1.19E-2		-3.79E-3		0.47	
	ECT(-1)	-1.71***		-1.33***		-0.75***		-1.30***		-1.57***		-1.52***		-1.12***	
	R^2	0.81		0.64		0.71		0.71		0.82		0.62		0.41	
	Adj. R^2	0.75		0.59		0.65		0.59		0.77		0.52		0.39	
	S.E. of Reg.	0.02		0.02		0.02		0.03		0.02		0.03		0.05	
	SSR	0.02		0.02		0.01		0.03		0.01		0.03		0.02	
	F-stat.	14.60***		13.05***		12.74***		6.15***		16.01***		6.43***		4.77***	
	D-W stat	1.81		1.87		2.22		2.08		2.11		1.62		2.02	
	J-Bera Test	x^2: 0.37 (Prob: 0.83)		x^2: 0.11 (Prob: 0.95)		x^2: 1.20 (Prob: 0.55)		x^2: 1.15 (Prob: 0.56)		x^2: 0.82 (Prob: 0.66)		x^2: 0.34 (Prob: 0.84)		x^2: 0.67 (Prob: 0.72)	
	B-G LM Test	x^2: 2.78 (Prob: 0.10)		x^2: 2.03 (Prob: 0.14)		x^2: 1.16 (Prob: 0.32)		x^2: 0.44 (Prob: 0.65)		x^2: 0.55 (Prob: 0.59)		x^2: 2.34 (Prob: 0.12)		x^2: 3.48 (Prob: 0.13)	
	BPG LM Test	x^2: 1.89 (Prob: 0.33)		x^2: 1.15 (Prob: 0.35)		x^2: 2.52 (Prob: 0.02)		x^2: 0.87 (Prob: 0.59)		x^2: 0.56 (Prob: 0.76)		x^2: 2.52 (Prob: 0.10)		x^2: 1.10 (Prob: 0.37)	
	Ramsey RESET	x^2: 0.74 (Prob: 0.40)		x^2: 5.14 (Prob: 0.28)		x^2: 0.14 (Prob: 0.71)		x^2: 0.00 (Prob: 0.96)		x^2: 0.48 (Prob: 0.50)		x^2: 3.48 (Prob: 0.10)		x^2: 0.79 (Prob: 0.38)	
Spring	*LogGSP*	0.93**	1.97***	1.93***	1.26***	0.67***	0.62	0.75	0.58	0.77***	0.37	1.19	1.15	1.66E-4	1.15E-4
	POP	-13.02*	-15.36**	-20.92*	-15.21	-34.96**	7.16	-35.74***	-27.78**	-15.52**	-6.88	-3.71	-3.59	-48.48	-33.44
	PR	5.63E-5	3.96E-4***	2.89E-4	1.88E-4	-2.04E-4	1.87E-4	6.83E-4***	6.65E-4**	-1.50E-5	-1.10E-5	3.56E-4	3.45E-4	1.10E-3***	7.62E-4***
	CDD	2.56E-3***	5.47E-3***	6.76E-3**	9.66E-3*	1.32E-3**	1.61E-2**	8.47E-3***	6.53E-3***	7.70E-3***	5.65E-3***	-6.60E-3	-6.39E-3	3.68E-3**	2.54E-3**
	HDD	3.00E-3***	4.33E-3***	1.93E-3**	2.20E-3	2.25E-3**	9.44E-3	-1.41E-3	-1.13E-3	2.81E-3***	2.06E-3***	9.85E-3***	9.53E-3***	-2.23E-3	-1.54E-3
	Constant	-7.11E-3		-1.75E-2***		-3.96E-3		-7.18E-3		-2.42E-3		-6.34E-3		-3.99E-2	
	ECT(-1)	-1.97***		-1.54***		-0.73***		-1.30***		-1.36***		-1.03***		-1.45***	
	R^2	0.68		0.84		0.97		0.62		0.65		0.63		0.40	
	Adj. R^2	0.66		0.76		0.93		0.53		0.51		0.54		0.38	
	S.E. of Reg.	0.03		0.02		0.01		0.03		0.02		0.03		0.05	
	SSR	0.02		0.01		0.00		0.04		0.01		0.02		0.04	
	F-stat.	26.54***		10.15***		27.26***		6.62***		4.45***		6.92***		6.12***	
	D-W stat	2.08		2.27		1.92		2.08		2.14		1.79		2.06	
	J-Bera Test	x^2: 1.12 (Prob: 0.57)		x^2: 0.42 (Prob: 0.81)		x^2: 0.22 (Prob: 0.90)		x^2: 0.88 (Prob: 0.74)		x^2: 0.86 (Prob: 0.65)		x^2: 0.97 (Prob: 0.62)		x^2: 1.14 (Prob: 0.33)	
	B-G LM Test	x^2: 4.78 (Prob: 0.09)		x^2: 1.37 (Prob: 0.27)		x^2: 0.04 (Prob: 0.96)		x^2: 0.63 (Prob: 0.54)		x^2: 1.14 (Prob: 0.34)		x^2: 2.62 (Prob: 0.10)		x^2: 1.23 (Prob: 0.30)	
	BPG LM Test	x^2: 2.71 (Prob: 0.06)		x^2: 0.94 (Prob: 0.54)		x^2: 1.54 (Prob: 0.16)		x^2: 1.47 (Prob: 0.19)		x^2: 1.06 (Prob: 0.43)		x^2: 1.45 (Prob: 0.24)		x^2: 1.65 (Prob: 0.13)	
	Ramsey RESET	x^2: 1.21 (Prob: 0.27)		x^2: 0.46 (Prob: 0.51)		x^2: 0.28 (Prob: 0.60)		x^2: 0.86 (Prob: 0.36)		x^2: 1.24 (Prob: 0.28)		x^2: 1.46 (Prob: 0.24)		x^2: 1.22 (Prob: 0.27)	

Notes: *** indicates significance at the 1% level, ** indicates significance at the 5% level, and * indicates significance at the 10% level. *LogPE* is the log of per capita energy consumption, *LogEX* is the log of energy commodity expenditure, *LogDI* is the log of disposable income per capita, *POP* is population; *CDD* is cooling degree days, *HDD* is heating degree days, and AVP is average price indices of energy (electricity and natural gas). R^2 is R-squared, Adj. R^2 is adjusted R-squared, S.E. of Reg is standard error of regression, SSR is sum of squared residuals, F-stat is F-statistics for the regression model, and D-W stat is Durbin–Watson statistical test for autocorrelation. For the residual diagnostic tests, please note that x^2 is the statistic or F-statistic; further, P-values are in parentheses and calculated to the nearest two decimal points. The Durbin–Watson statistical test (D-W stat) considers the null hypothesis that the residuals are not autocorrelated against the alternative hypothesis that the residuals follow an AR1 process. The Jarque–Bera test considers the null hypothesis that the residuals are normally distributed (the histogram will be bell-shaped and the P-values or Prob will not be significant) against the alternative hypothesis that the residuals are not normally distributed. Although the D-W stat is around 2, which shows that the null hypothesis of no autocorrelation is accepted, a further serial correlation test was required because there are lagged dependent variables on the right side of the ARDL model. The presence of these lagged dependent variables invalidates the D-W stat; thus, a test is required for higher order autocorrelation errors which are not affected by lagged dependent variables on the right side. In order to overcome this limitation, the Breusch–Godfrey Lagrange multiplier (B-G LM) test was applied to test the null hypothesis of no serial correlation up to lag *p* against the alternative hypothesis of serial correlation. The Breusch–Pagan–Godfrey Lagrange multiplier (BPG LM) test considers the null hypothesis of no heteroscedasticity against the alternative hypothesis of heteroscedasticity. The Ramsey regression specification error test (RESET) considers the null hypothesis that the functional form is correctly specified against the alternative hypothesis of functional form misspecification.

From Table 3.1, some specific effects of climate change on electricity demand in Australia are found in states located in the northern regions (e.g. QLD and the NT), where higher electricity demand is expected during the summer compared with other states. Some states located in the southern region (VIC, SA, and TAS) experience higher electricity demand during the winter months.

In the NT, where demand for cooling is frequent throughout the year, higher CDD coefficients are observed during the summer months for the short and long terms (1.51% and 1.36% respectively) compared with the other seasons. These findings imply that utility providers need to be more concerned about the increase in peak demand for cooling during the summer months in the NT than during other seasons. Because of the differences in seasonal electricity demand for the six states and one territory in Australia considered here, there is a high tendency for the export of electricity to QLD during the summer months, while electricity may be imported to the southern states (e.g. NSW, VIC, and SA).

This electricity trade in Australia occurs between states under the National Electricity Market (NEM), which includes NSW, VIC, QLD, SA, and TAS. The NT and WA operate a separate electricity market called the Interim Northern Territory Electricity Market (I-NTEM) and South West Interconnected System (SWIS) respectively. When an increase in temperature in a state results in increased electricity demand which is higher than the generated electricity, power from other states can be imported to balance supply. For example, SA has constantly been exporting power to VIC to meet the latter's rising demand and prevent blackouts.[24] In the case of isolated electricity markets such as the SWIS, increased seasonal demand which does not match electricity generation results in blackouts, as occurred in 2016.[25] Thus, efficient electricity demand forecasting is vital in order to prevent future blackouts.

The insensitivity of GSP to electricity demand in these six states and one territory in different seasons may be due to such factors as a substitution effect, efficiency possibilities, and changes in economic activities during a particular season of the year. Comparing the results with GSP growth, published by the ABS (Statistics, 2018), the

[24] See https://myaccount.news.com.au/sites/heraldsun/subscribe.html?sourceCode=HSWEB_WRE170_a_GGL&mode=premium&dest=http://www.heraldsun.com.au/news/national/south-australia-exporting-power-to-victoria-as-eastern-state-imports-tumble-tenfold/news-story/.

[25] See http://reneweconomy.com.au/big-w-a-blackout-cant-be-blamed-on-renewables-doesnt-make-headlines-75160/

positive coefficient for GSP suggests that states and territories with higher GSP consume more electricity. A similar study by Burke and Abayasekara (2017) showed that states in the US with higher per capita GDP consumed more electricity in the commercial sector. The change in economic growth in the long term differs to that in the short term in as shown in Table 3.1.

This result may relate to energy efficiency improvements, which influence the consumer savings reflected in GSP in the long term (Borg and Kelly, 2011, Fouquet and Pearson, 2012). Further, technological improvements are less likely to be correlated with fluctuations in income in the short term because such improvements relate to energy consumption (Wang et al., 2016a). However, it is important to note that energy efficiency improvements may not necessarily lead to a reduction in energy consumption. The reason is that consumers may prolong the use of energy-efficient appliances in an inefficient manner, which may in turn increase energy consumption (Jevons, 1866, Alcott, 2005). Thus, it may prove challenging to capture the influence of GSP in the long term because energy-efficient consumers may use extra savings for other economic purposes. A disaggregate approach, through a sectorial or micro-level analysis, could improve the accuracy of the current result.

Utility companies usually respond to an increase in electricity demand by expanding generation capacity in order to provide adequate electricity. In this regard, population is an important factor which contributes to changes in electricity demand. Moreover, population changes may show some seasonal patterns due to the migration of residents from other states, regions, or countries. The findings from Table 3.1 show that in general, the growth in a state's population is not associated with an increase in electricity demand. Price elasticity in the short and long term is inelastic during the summer in NSW (0.04 and 0.05 respectively) and VIC (0.05 and 0.09 respectively), while NT has a long-term price elasticity of 0.46. Consumers in NSW and QLD respond slightly proportionately to changes in the electricity price in autumn because long-term elasticity is higher than short-term elasticity. The price elasticity for demand in VIC and NT is inelastic with regard to the prior season (summer), implying that the states and territories are not responsive to changes in electricity prices during warmer temperatures.

From the results presented in Table 3.1, price elasticity is generally observed to be less sensitive to electricity demand in most seasons across the states and territories in Australia. There are two notable reasons for this response: consumers' fixed rate plans and the three-month electricity billing cycle for consumers with analogue meters. The fixed rate plan is popular with Australian energy providers and tends to bind consumers to particular energy companies for what is usually two years. Because of such contracts, consumers may not be able to change utility providers; if they do, they incur penalty costs associated with the contracts.

Consumers who use analogue meters may also be insensitive to price changes because they receive their electricity bills after three months. These bills do not show areas of potential energy conservation or efficiency improvements (e.g. energy-efficient appliances). An option involves charging consumers on a monthly basis, which is possible when analogue meters are replaced with smart meters. This approach promotes energy efficiency because consumers become more aware of their consumption habits and make efforts to reduce electricity consumption or use efficient appliances.

However, studies such as Alberini and Filippini (2011), Bernstein and Griffin (2006), and Paul et al. (2009) found that energy demand was insensitive to changes in energy prices. In Meier et al. (2012), an increase in spending on energy commodities due to changes in the energy price is associated with an increase in household income in British households. In autumn in the Australian states of NSW, QLD, and TAS, where the energy price is elastic to demand, residents tend not to adjust their demand because of a price change in the short term; instead, they make an adjustment in the long term. The adjustment indicates a higher insulation rate in buildings, energy efficiency improvements, and a change to other fuels or technologies.

3.5.2. Residual Diagnostic and Stability Test

The dynamic behaviour of electricity consumers was further modelled by incorporating a short-term adjustment factor into the long-term model (Equation 3.3). This process involved the substitution of an error correction term (ECT) for the variables in their levels using the one-period lag residuals from the model presented in Equation (3.3). As recommended by (Pesaran et al., 2001), an ECT should be substituted because it has a more parsimonious specification than the ARDL in Equation (3.8). The following represents the short-term ECT model:

$$\Delta \log(EL_t) = a_0 + \sum_{i=1}^{p} a_i \Delta \log(EL_{t-1}) + \sum_{i=0}^{q_1} b_i \, \Delta \log(GSP_{t-1}) \sum_{i=0}^{q_2} c_i \Delta POP_{t-1} + \sum_{i=0}^{q_3} d_i \Delta PR_{t-1} + \sum_{i=0}^{q_4} e_i \Delta CDD_{t-1} + \sum_{i=0}^{q_5} f_i \Delta HDD_{t-1} + ECT_{t-1} + \varepsilon_t \qquad Eq. (3.13)$$

where all variables are as previously defined in Equation (3.8). The ECT is the deviation of electricity consumption from its long-term mean estimated by ordinary least squares. The coefficient measures the speed of adjustment in current electricity consumption to prior disequilibrium demand value. Further, the coefficients of the ECT (t – 1), which is the lag residual from the long-term equation, should have a negative sign and be significant (Enders, 2004). The ECTs for the six states and one territory (see Table 3.1) are all significant and have the expected negative signs in the four seasons.

This finding proves the existence of a long-term relationship which is dynamically stable because the coefficients are not lower than -2 (Loayza et al., 2006). During the summer, when demand is above or below equilibrium, the electricity consumption adjustments of the six states and one territory are 1.54% in NSW, 1.63% in VIC, 1.45% in QLD, 1.85% in SA, 1.49% in WA, 1.71% in TAS, and 1.70 in NT. The ECTs during the summer are observed to be higher than in the other seasons in the six states and one territory except WA (autumn) and NSW (winter and spring). Across the six states and one territory, a slower speed of adjustment is observed in QLD, while autumn and winter have the lowest speeds of adjustment. As further observed from the results in Table 3.1, the speeds of adjustment are not uniform across the six states and one territory. Issues related to the seasonal variations in the speeds of adjustment merit further investigation.

The residual diagnostic test for the split-sample ARDL model used in this study includes the Durbin–Watson test (Durbin and Watson, 1951). This tests for first-order serial correlation where the null hypothesis of no residual autocorrelation has been accepted in all models. In order to test further for serial correlation for higher-order autocorrelation, the Breusch–Godfrey (Breusch, 1978, Godfrey, 1978a) Lagrange multiplier was applied and the null hypothesis of no serial correlation was accepted. In order to test for the existence of heteroscedasticity, the Breusch–Pagan–Godfrey (Breusch and Pagan, 1979, Godfrey, 1978b) Lagrange multiplier test was employed and the null hypothesis of no heteroscedasticity was accepted. The Jarque–Bera (Jarque and Bera, 1980) test accepted the null hypothesis that the residual is normally distributed as opposed to the alternative hypothesis of non-normal distribution of the residual.

With regard to the stability diagnostic test, the Ramsey regression specification error test (Ramsey, 1969) was used to test for functional form misspecification. The null hypothesis confirmed that the functional form was properly specified in the model. Finally, following Brown et al. (1975) and as recommended by Pesaran and Pesaran (1997), the cumulative sum of the recursive residual (CUSUM) and the CUSUM of squares tests (CUSUMSQ) were used to investigate parameter instability of the split-sample ARDL model. The results (see Figure A4.1 in Appendix 4) of the CUSUM test clearly indicate stability of the coefficients during the sample period. The cumulative sum in the CUSUMSQ test is within the 5% significance level, indicating that the residual variance is stable for the period of observation.

3.5.3. Model's Accuracy

Since the results of the ARDL model will be used to predict future climate-induced electricity demand, the accuracy of the model needed to be evaluated. This evaluation was based on possible combinations of weather and socio-economic variables, and the presence of MAPE. In this regard, monthly electricity demand was estimated from 1999 to 2010 for NSW. Older monthly electricity data sets were unavailable; further, this study relied on available electricity and price data from AEMO (Operator, 2017c), and population and GSP data from ABS (Statistics, 2016c). CDD and HDD data were calculated from prior temperature data obtained from the BOM (Meteorology, 2017). In order to demonstrate the effectiveness of using the ARDL model’s coefficients for electricity demand forecasting, this study estimated the model presented in Equation (3.3) using MLR. Further, in order to predict electricity demand for the year ahead, the coefficients of the ARDL model for 1999–2004 were used to predict demand for 2005, while the coefficients for 2005–2009 were used to predict demand for 2010.

Finally, in order to test the reliability of the ARDL estimate, this study conducted a form of forecast using the M approach presented in Equation (3.9) and calculated the MAPE and standard deviation. It is worth noting that at this stage, the adjustment factor (Equation 3.10) which accounts for changes in climatic and socio-economic parameters was not calculated. The findings regarding the model's accuracy from 1999–2010 are presented in Table A5.1 in Appendix 5. They include the M approach from Equation (3.9). From the MAPE presented in Table A5.1, it is evident that the ARDL model generates a lower MAPE compared with the MLR model and is much more effective than the M approach. Moreover, for the ARDL model, the climatic variables are observed to be more predictive than the socio-economic parameters, with a lower standard deviation. Indeed, a more detailed estimate presented in Figure A5.1 in Appendix 5 shows that the ARDL model with climatic parameters alone is more predictive during the summer, March, and October from 1999 to 2010.

In order to improve the estimated M approach, this study included the adjustment factor and conducted a detailed forecast for each month in 2005 and 2010 to determine the forecast accuracy of the improved F approach, following Equation (3.11). The results of the forecast accuracy test are presented in Figure A5.2 in Appendix 5. They include the modelled, actual, and F estimated monthly values in panel A1 for 2005 and panel B1 for 2010. From Figure B2, a visible winter peak demand for 2005 and 2010 can be seen to occur on 23 June and 29 June[26] respectively. Remarkably, the estimated demand, F, which has been adjusted, is able to predict peak demand more effectively, with an absolute error of 0.99% in 2005 and 0.99% in 2010. The accuracy of simulation and forecasting during the summer months improved compared with the winter forecast. This improvement is consistent with the findings of Apadula et al. (2012).

In general, actual and forecasted electricity demand are similar because the absolute percentage errors range from 0.18 to 2.21% in 2005 and 0.19 to 1.51% in 2010. The model's accuracy (in terms of MAPE) is 0.88 ± 0.65% for 2005 and 0.89 ± 0.58% for 2010. Since these MAPEs are within acceptable limits, this study applied the coefficients of the ARDL estimates as the adjustment factors to the method used in Equation (3.11) in order to simulate future electricity demand. This approach was necessary since this study

[26] See https://www.aer.gov.au/wholesale-markets/wholesale-statistics/seasonal-peak-demand-occurrence-region

intended to restrict the adjustment factors to future temperature changes using climate change scenarios. The process is described in the following section.

3.5.4. Simulations

This section simulates the impacts of temperature changes on electricity demand using four different IPCC RCP scenarios, three different economic growth scenarios, three levels of energy efficiency scenarios, three renewable energy technology targets, and three different electricity price scenarios. Following the literature on climate change impact, electricity consumption for each state was calculated until 2100. The impacts of uncertainty in the scenarios were simulated in sequential order as follows.

3.5.4.1. Temperature Simulations using Climate Change Scenarios

In order to simulate the influence of temperature changes on electricity demand in climate change conditions, temperature sensitivity to electricity demand and projected temperature changes were required. Temperature sensitivity is the estimated coefficient of CDDs and HDDs in Table 3.1. It is also the seasonal response to the climate. Following the literature, this study assumed that response to the climate remains constant until the end of the century in each of the six states and one territory (Aroonruengsawat and Auffhammer, 2011). The reason is that although consumers in colder regions are expected to purchase cooling appliances, those in warmer regions increase their investment in cooling appliances when the temperature increases because of climate change. However, with new technologies come improved energy efficiency standards which lead to increased energy savings and reduced energy costs. This situation is simulated in Section 4.4.2.

Future temperature projections were retrieved from GCMs under the coupled model intercomparison project phase 5 (CMIP5). The CMIP5 comprises the latest generation of GCMs with a horizontal spatial resolution of approximately 200 km, although the resolution becomes significantly finer over time. Following the recommendations of *Climate Change in Australia*[27], developed and operated by the

[27] See https://www.climatechangeinaustralia.gov.au

Commonwealth Scientific and Industrial Research Organisation, the community earth system model version 1, which includes the community atmospheric model version 5 (CESM1–CAM5) was selected to ensure the model's performance. This selection was based on the model's ability to generate the required minimum and maximum temperature data sets using the four IPCC RCP[28] scenarios and the high degree of model performance based on the *M* scores (see Table 5.2.2 in Meinshausen et al. (2011)). For a more detailed description of the CESM1–CAM5 model, see Meehl et al. (2013).

The RCPs examined in this study are RCP 2.6, RCP 4.5, RCP 6.0, and RCP 8.5. This approach followed the expected range of radiative forcing values by 2100 relative to pre-industrial values. The CESM1–CAM5 model projected changes in future temperatures from the historical period 1986 to 2005. The projected periods were the 2030s (2016–2045), 2050s (2036–2065), 2070s (2056–2085), and 2090s (2075–2104). The projected future temperatures of the CESM1–CAM5 were used to calculate future CDDs and HDDs (following Equations (3.4) to (3.7)) on a daily basis and aggregated to month- and period-wise patterns, as shown in Figure A6.1 in Appendix 6. The results show a uniform decline in the heating requirement across the periods in the six states while the cooling requirement increases. In NT, cooling is required from the 2030s–2090s. On a monthly basis, the cooling requirement increases during November and peaks around January; thereafter, it declines in March. An increased heating requirement is observed in QLD during the 2090s compared with other periods, while the CDDs rapidly decline by 2090.

The results for TAS and NT are unsurprising because their geographical locations have a significant influence on their cooling and heating requirements. For example, higher temperatures within NT compared with other states in every month of the year entail increased demand for cooling all year round. The increase in the cooling requirement also leads to the gradual increase of AC adoption across the southern states, while the states and territory located in the northern regions experience an increased cooling requirement in the 2050s to the 2070s. As Clarke et al. (2018) pointed out, the projected increase in AC adoption from 2050 to 2100 may not be income related in

[28] The RCP scenarios are somewhat consistent with socio-economic assumptions based on possible changes in human GHG emissions. Global annual GHG emissions are assumed to peak between 2010 and 2020 and to decline substantially in RCP 2.6; emissions peak around 2040 and decline in RCP 4.5; emissions peak around 2080 and decline in RCP 6.0; but emissions continue to rise throughout the twenty-first century in RCP 8.5.

temperate, developed countries. However, a fall in prices and improved energy efficiency may encourage the increased use of AC (Jevons, 1866, Alcott, 2005).

The simulation of future electricity demand in climate change conditions was estimated following Equation (3.11), where the adjustment factor was calculated by multiplying the long-term coefficient of CDDs and HDDs from Table 3.1 by the future CDDs and HDDs for each month and year. It is important to note that the percentage electricity demand for future periods is based on a strong assumption that response to the climate by consumers in the future will remain unchanged in accordance with their current response to the climate for 1990–2016. This is a standard assumption in the literature, where future cooling and heating electricity consumption follow an uncertain income level and electricity price which may influence consumers' behaviour and energy policies (Damm et al., 2017). Although Véliz et al. (2017) conducted a forecast of electricity price and expenditure, consumers' response to future price changes in climate change conditions remains unclear in the literature, although studies suggest that the current response to price will be similar in the future.

Across the RCP scenarios (see Figure 3.3 – Figure 3.6), it can be observed that the six states and one territory have upward sloping climate-response functions (see Table 3.1), which result in increases in electricity demand due to increased CDDs rather than HDDs. For example, SA electricity demand for cooling increases during January and February from the 2030s to 2090s when temperature responses are high. In January and February in 2017[29] and 2018,[30] SA experienced a series of heatwaves when temperatures were above 40°C. These heatwaves resulted in blackouts due to a lack of energy reserves. Thus, the results presented in Figure 3.3 – Figure 3.6 can be used for electricity generation planning. The states and territory with downward slopping climate-response functions and a larger number of degree days tend to have the highest increase in electricity demand. For example, WA tends to have increased demand during winter months compared with summer months.

[29] See http://www.abc.net.au/news/2017-02-08/sa-heatwave-forces-rolling-blackouts-angering-government/8252512
[30] See http://www.afr.com/news/politics/aemo-warns-about-impending-heatwave-to-hit-south-australia-victoria-nsw-20180116-h0ji5a

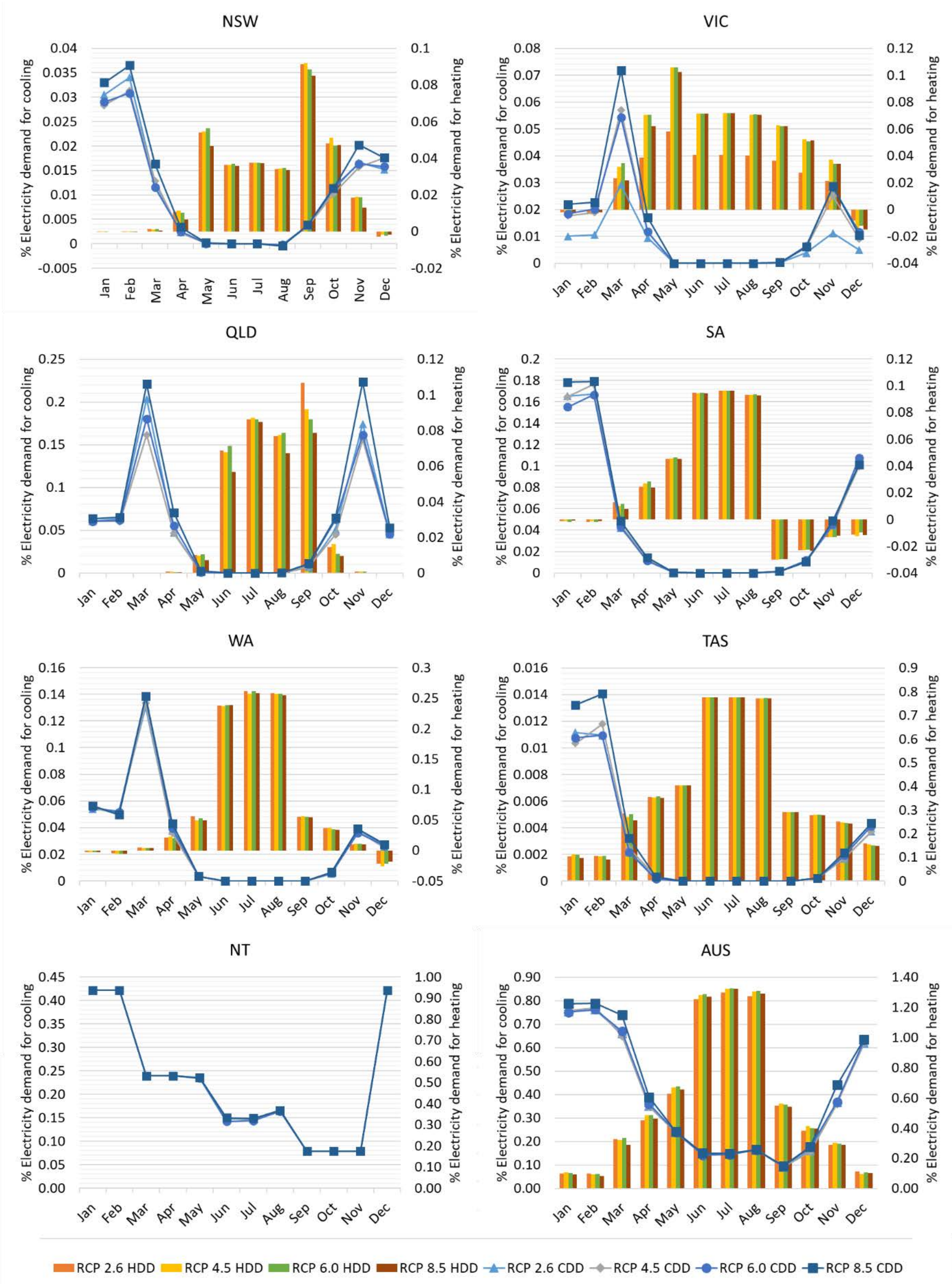

Figure 3. 3: Electricity demand sensitivity to climate change (2030s).

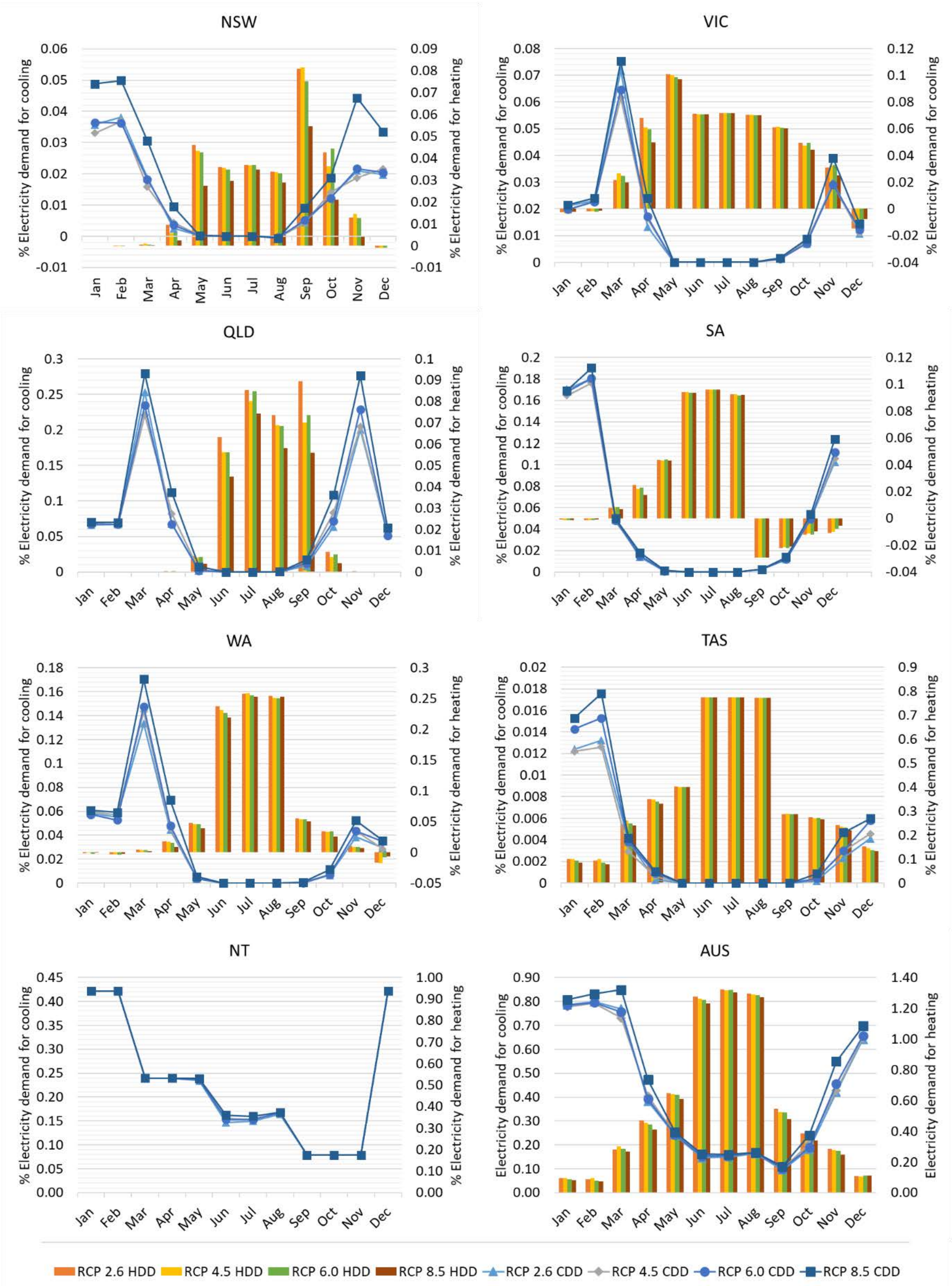

Figure 3. 4: Electricity demand sensitivity to climate change (2050s).

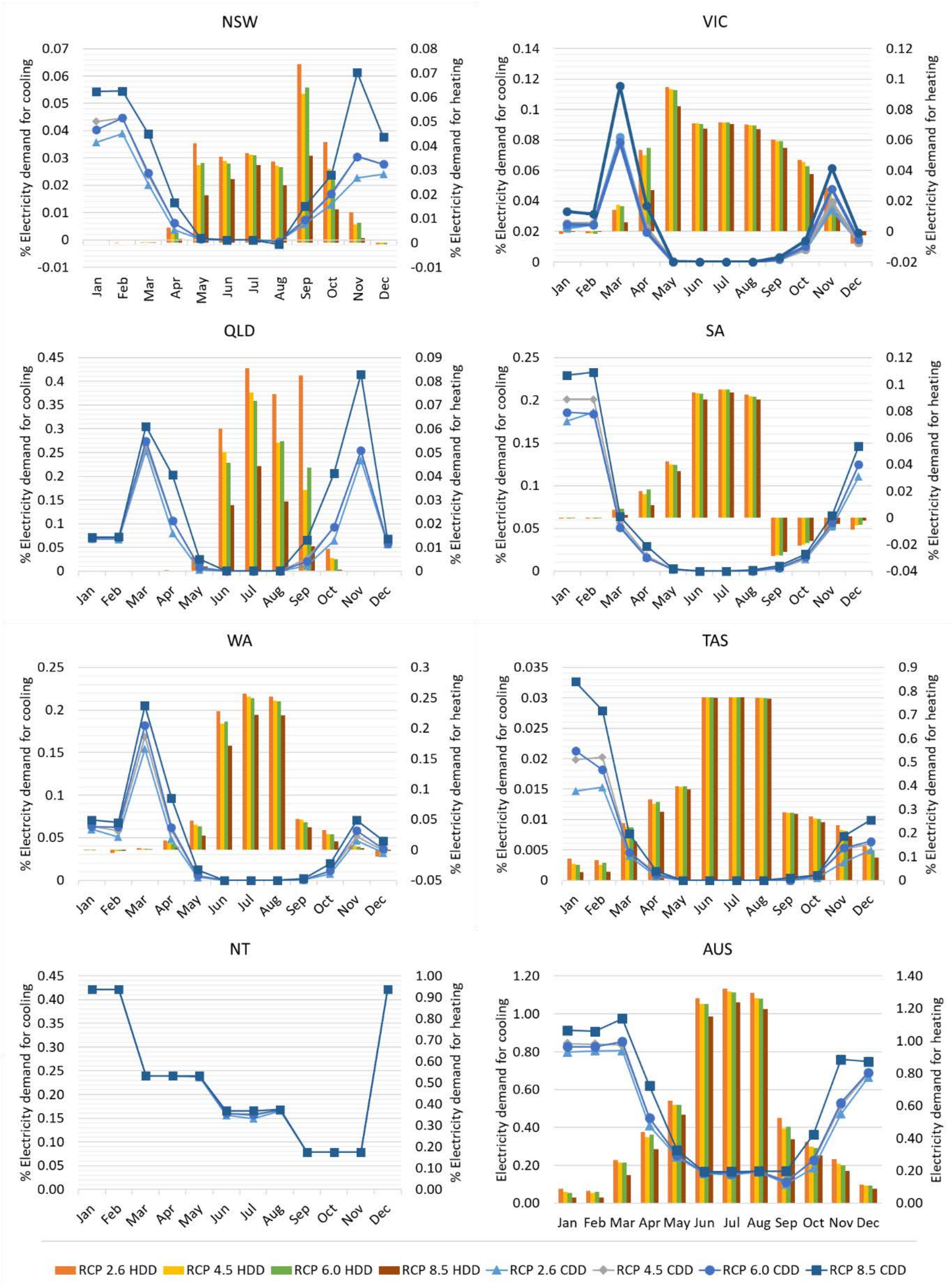

Figure 3. 5: Electricity demand sensitivity to climate change (2070s).

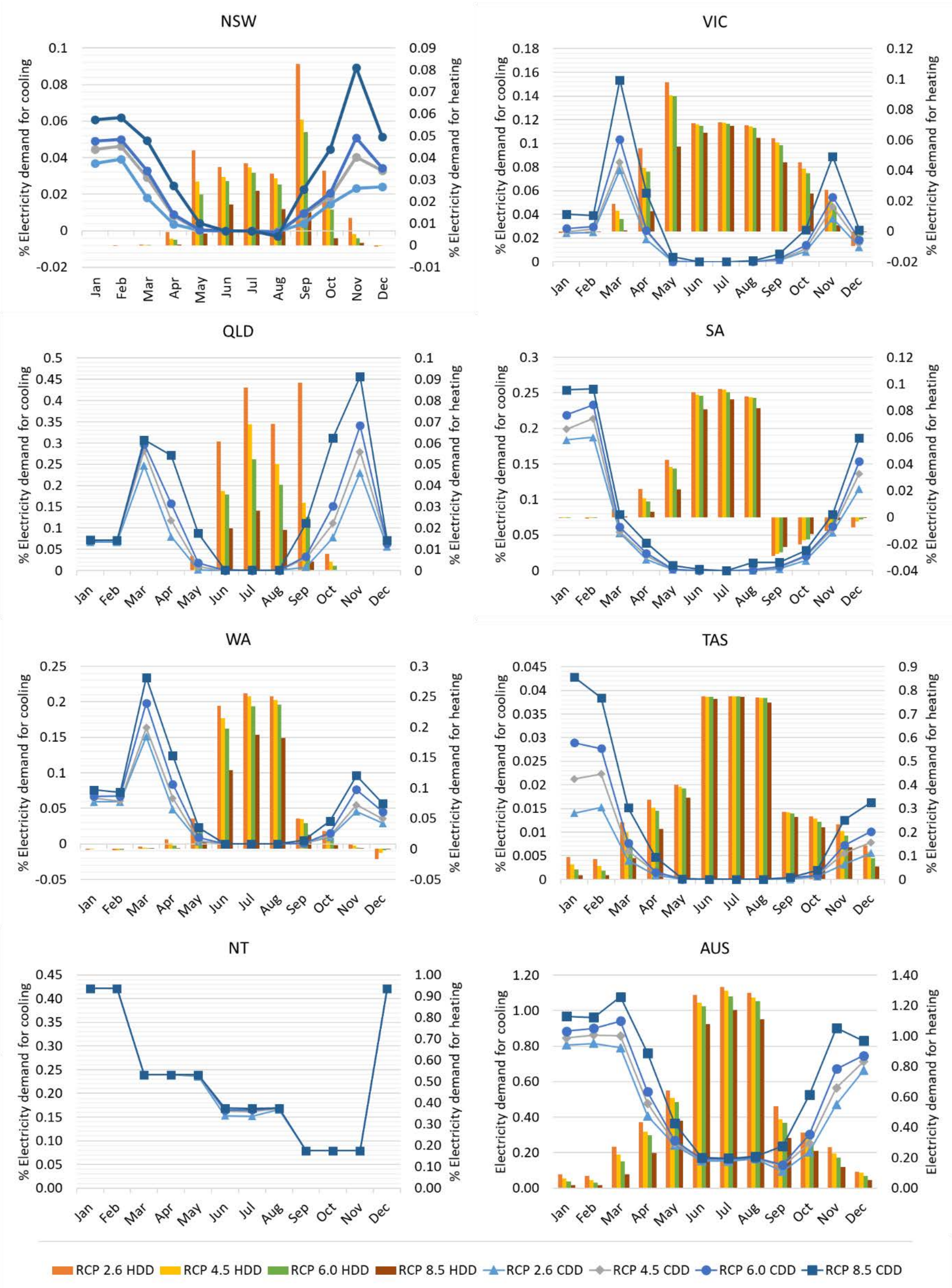

Figure 3. 6: Electricity demand sensitivity to climate change (2090s).

This is unsurprising because an AEMO report showed that winter maximum demand will grow moderately close to summer maximum demand values from 2016 to 2036 (Operator, 2016a). Thus, this study indicates that the states and territory which experience lower temperatures during the winter months tend to have higher electricity demand due to response to the climate. This finding contrasts with the study of Aroonruengsawat and Auffhammer (2011) who stated that in California, higher temperatures had very large increases in electricity demand.

Although electricity demand for heating is expected to decline in accordance with the global increase in surface temperature, the southern state of VIC may experience a minor decrease in electricity demand for heating by the end of the century. This minor decrease may be due to the increase in reverse cycle AC, which in 2014 had a penetration rate of 37.7% (Statistics, 2014). Reverse cycle AC systems have space heating functions and are more efficient than conventional gas heaters. Thus, a minor decrease is expected because consumers may not change to gas heaters on the grounds that reverse cycle AC systems consume 20% less energy (Operator, 2016a, Li et al., 2012a).

Monthly peak demand is the maximum electricity demand (see Figure A6.2 in the Appendix). In the four RCP scenarios until the 2090s, higher peak electricity demand should be expected around September in NSW; May in VIC (although this changes to March from the 2070s onwards); March and November in QLD; January and February in SA; July and August in WA; June, July, and August in TAS; and January, February, and December in NT. It is observed that most of the high peak demand does not occur during months with more degree days, but during warmer temperatures and higher levels of response to the climate. This finding is consistent with those of Bartos et al. (2016b) and Auffhammer et al. (2017). However, the peak load tends to move between two seasons. This movement may be due to the behaviour of consumers in response to a changing climate (Fan and Hyndman, 2014).

The percentage changes in electricity demand, which are the percentage differences between the current and prior months under observation, are presented in Figure A6.3 in the Appendix. The percentage change in electricity demand in TAS during the winter month of June is projected to be as high as 0.35%, increasing to 0.43% in RCP 8.5 by the 2090s. From the climatic projections for changes in future temperatures and electricity demand response, the projected growth in yearly electricity demand is presented in Figure 3.7. In conditions with a lower concentration pathway (RCP 2.6), electricity demand decreases mid-century in VIC, QLD, SA, TAS, and NT, while the highest carbon concentration pathways are associated with the highest electricity demand. However, NSW and WA are projected to experience a gradual decline in electricity demand across the scenarios by mid-century compared with the base period.

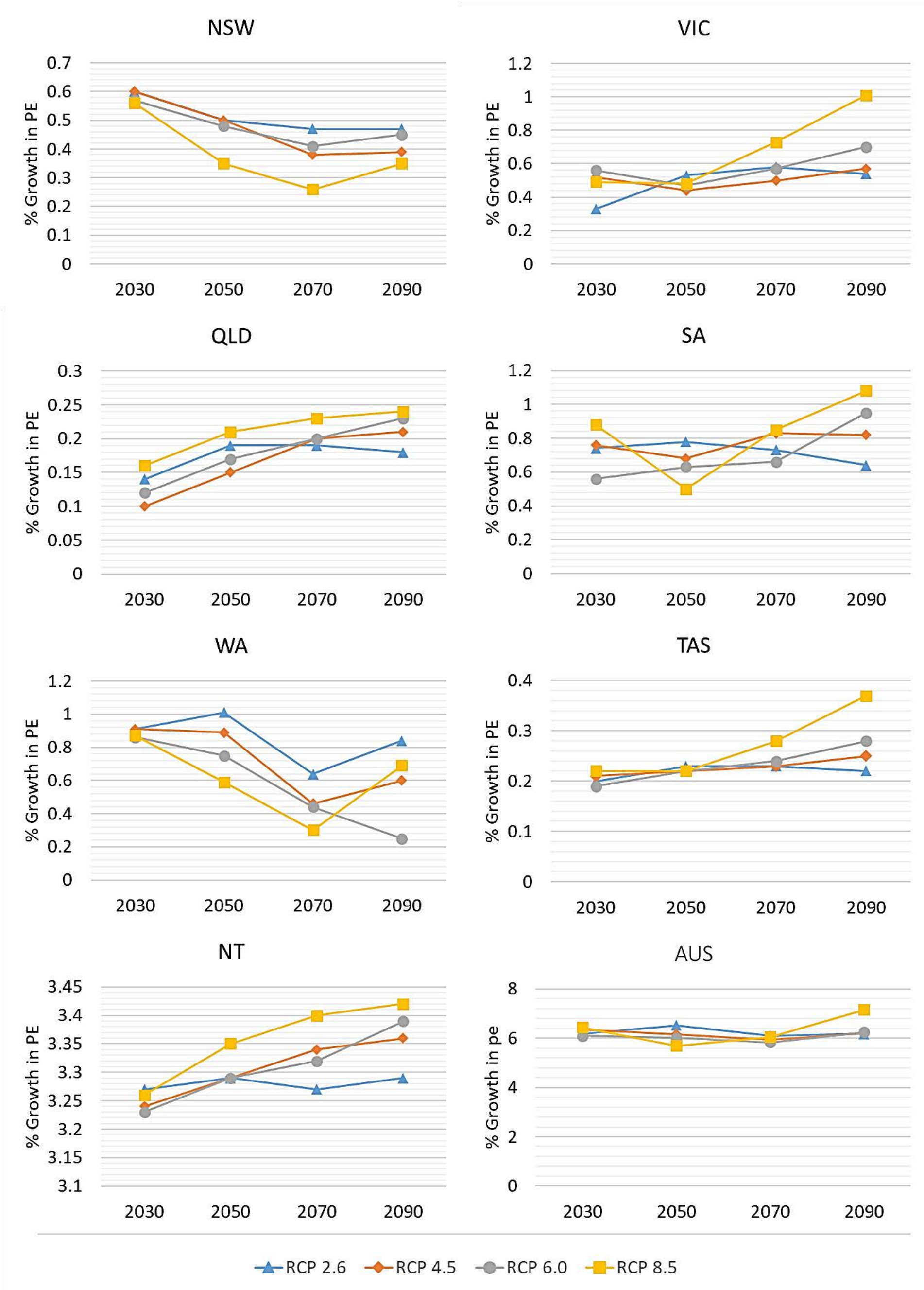

Figure 3. 7: Percentage growth in electricity demand.

Further, a comparison of Figure 3.3 – 3.6 and Figure 3.7 shows that the decrease in electricity demand for heating offsets the increase in cooling demand in NSW and WA. A similar situation was observed by Xu et al. (2012) in their study of different buildings in California, where the decrease in total energy use in buildings is offset by an increase in cooling demand. The states and territory with higher electricity demand for cooling or heating by the end of the century tend to experience higher annual energy demand in the RCP 8.5 scenario. The increased growth in demand is expected to result from the increased use of AC in the states and territory with warmer temperature such as NT and QLD. Annual electricity demand is expected to remain stable until the end of the century, except in the higher concentration scenarios.

3.5.4.2. Policy Uncertainty Assessment

The review of Chandramowli and Felder (2014) classified three climatic uncertainties: impact (climate change damage, the intensity and frequency of extreme events, feedback, and the interactive effects from mitigating technologies); policy (technological disruptions, market reforms, and the regulatory adoption of alternative technologies); and modelled climate types. The extent of climate change impacts on electricity have been studied in the current study's prior sections. As anticipated, most of the six Australian states and one territory will experience an increase in electricity demand due to temperature changes. Policy uncertainty remains an area of interest to policymakers in terms of adaptation to climate change and mitigation. However, the uncertainty depends on socio-economic and technological factors which may alter the degree of climate change impact on electricity demand (Bartos et al., 2016b). The literature suggests that future energy demand will be influenced by factors such as economic structure, the level of energy efficiency improvement, the penetration of alternative energy technologies such as renewables, and future electricity prices (Zhou et al., 2014).

This section considers policy uncertainty and improves energy demand forecasting in climate change conditions by accounting for changes in energy savings, energy efficiency, and fluctuations in electricity prices up to 2050. This study did not account for changes in the economic structure such as moving to a low energy intensive sector. However, changes in economic growth are followed by energy efficiency improvements. Such improvements are anticipated as new energy-efficient technologies for AC and heaters replace old inefficient systems. For simplicity, annual projected energy was estimated instead of seasonal energy demand. Further, LogGSP elasticities from the seasonal ARDL model in Table 3.1 were used to simulate energy demand in conditions of economic growth. Annual economic growth in a business-as-usual (BAU) scenario followed Syed (2014) up to 2050. In order to account for changes in annual economic growth, a ±5% was assumed for low and high concentration scenarios.

The literature has shown that economic growth is associated with energy efficiency improvements. Moreover, Australia has experienced steady economic growth, while energy intensity has steadily declined (Sandiford et al., 2015). This decline is attributed to the decoupling of economic growth from GHG emissions following the decrease in energy intensive industries, an increase in non-energy intensive sectors, an increase in energy efficiency, and the greater use of solar PV systems. Energy efficiency improvement was assumed to continue its historical trend from 1990–2016 at 0.8% per year, which is consistent with the Australian Treasury's suggested autonomous energy efficiency improvement rate for the RET (Syed, 2014, Authority, 2014b). The alternative assumed a ±0.5 for the low and high energy efficiency scenarios, where the low scenario is associated with lower economic growth and the high scenario has higher economic growth. The energy savings from efficiency improvements were estimated by subtracting the percentages saved from the forecasted growth in energy demand.

Further energy savings due to the introduction of the RET were simulated for the six states and one territory in climate change conditions. Although Australia has a 23.5% RET by 2020, each state and territory can set its own RET. Data on rooftop solar PV generation up to the year 2036 was taken from the AEMO (Operator, 2016a) and extended to 2050. Currently, WA does not have a RET;[31] thus, an average of the six states and one territory was applied. Finally, future energy demand under varying price changes was simulated using electricity price projection and the average price elasticity estimated in Table 3.1. This study used the BAU, weak scenario, and strong scenario price projections in Liisa Parisot (2017) to simulate price changes. Because data for price simulation were available for five states (NSW, VIC, QLD, SA, and TAS) within the NEM,

[31] See http://reneweconomy.com.au/graph-day-states-lead-renewables-leads-states-58329, last accessed 14 January, 2018.

the average was used for WA and NT. The results of the simulations are presented in Figure 3.8.

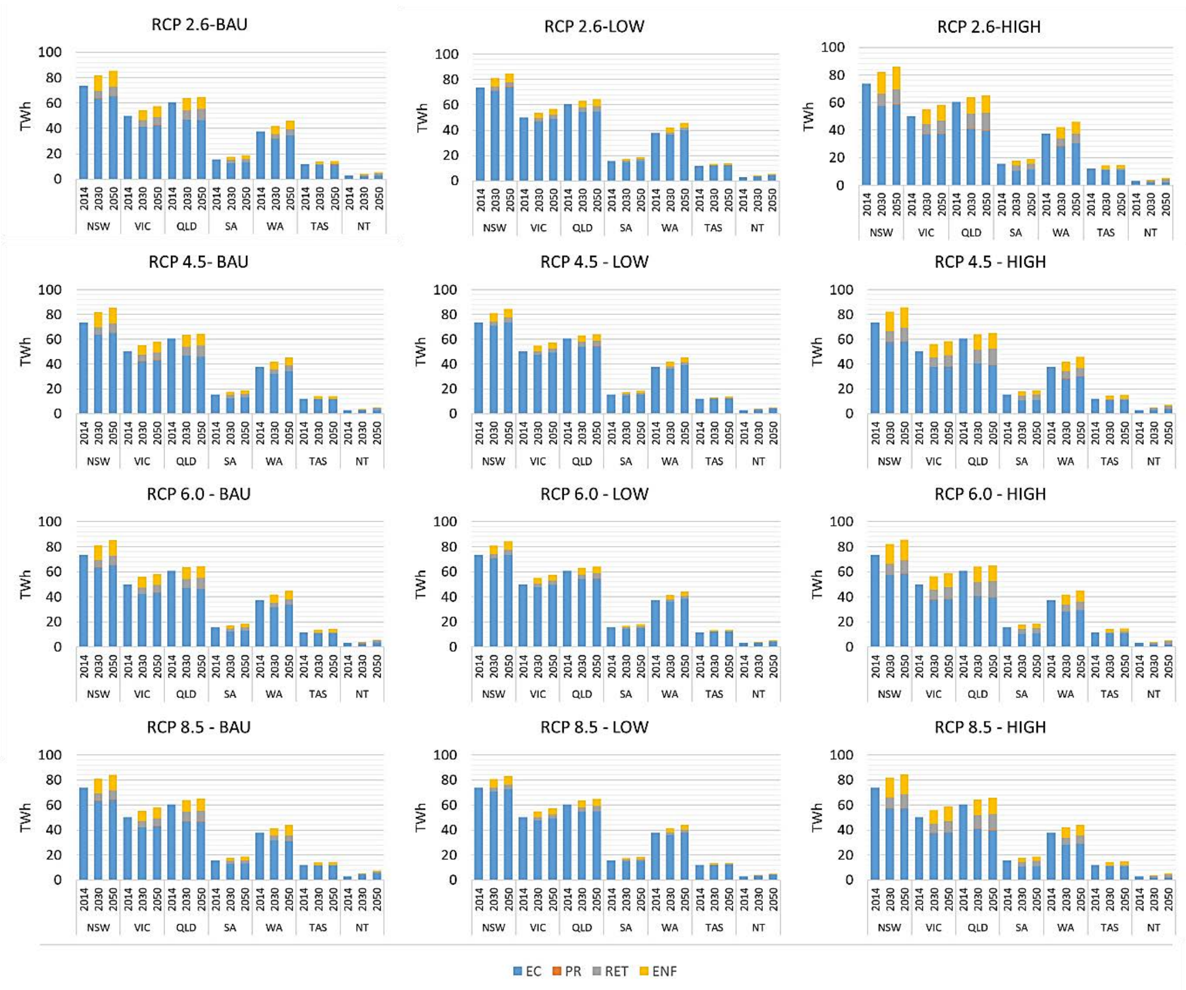

Figure 3. 8: Simulated effect of economic growth (EC), energy efficiency (ENF), renewable energy target (RET), and price changes (PR).

The results show that in climate change conditions and in the BAU scenario with no government policy, electricity demand increases to approximately 10 TWh in NSW, VIC, and WA, 5 TWh in QLD, and approximately 2–3 TWh in SA, TAS, and NT. Although energy efficiency policy is assumed to be the same in each state, the energy savings in climate change conditions tend to differ slightly across the four RCPs; however, the savings are very significant. For example, a higher energy efficiency target tends to be more suitable in the six states and one territory with higher fossil fuel consumption.

Further, the RET applied to each scenario tends to reduce overall energy demand below the base year value. Surprisingly, energy efficiency and RET policy result in the gradual reduction of electricity demand despite climate change conditions. As Borenstein (2015) explained, energy efficiency can have an equilibrium effect on the price of energy since it moves demand to the left side of the supply–demand curve. When this occurs, and the energy commodity supplied is less than perfectly elastic, energy demand decreases because energy efficiency results in a reduced commodity price (Gillingham et al., 2013). However, an overall increase in electricity demand is observed by mid-century in the higher concentration scenario (RCP 8.5) in the BAU and low scenarios.

Price changes are observed to be insignificant in the BAU and low scenarios in most of the six states and one territory, but are visible in the high scenario. This finding shows the effectiveness of the RET policy, which exerts downward pressure on wholesale electricity prices. However, smaller price elasticity, as shown in Table 3.1, can mean price-based polices, which are less effective in reducing electricity demand (Aroonruengsawat and Auffhammer, 2011). On the supply side, changes to electricity generation plant in the NEM, such as the retirement of older coal-fired plants and the inclusion of large-scale renewables, affects wholesale and retail prices (Commission, 2017). The changes in generation mix cause upward pressure on the price of hedging contracts because of the reduction in electricity supply since renewables are intermittent in nature. In the future, new technologies such as battery storage will enable the stability of renewable electricity supplies. Thus, the simulation presented in Figure 3.8 may change with an increased reduction in electricity demand due to price changes across the scenarios.

3.6. Discussion and Conclusion

This study investigated the short- and long-term impacts of temperature changes on electricity demand. Although socio-economic parameters were considered in our initial econometric analysis using an ARDL model, the impact of future temperature changes on monthly electricity demand was simulated and projected percentage growth to the end of the century. Our initial results were consistent with the findings of most studies which have anticipated increased electricity consumption due to warmer temperatures. This study also discovered the possibility of winter peaking, which is slightly higher than summer peaking in some southern Australian states. Although winter peaking is consistent with published reports, this peaking tends to reduce before the middle of the century across the RCP scenarios, especially RCP 8.5. However, summer peaking increases. The non-uniform growth in seasonal electricity demand, as shown in this study, may cause under-utilization of electricity generation capacity and exert pressure on utility providers. The implication of the underutilized capacity may have a wider economic impact on the NEM and RET which specify a target of 41,000 GWh by 2020.

The reason is that an oversupply of electricity may lead to a reduction of the RET because it may be assumed that with excess electricity in the system, renewables may have a minor role to play in a low carbon future. If winter peak demand declines in the southern Australian states before mid-century, policymakers and regulators can allow the electricity market to 'shake-out' as excess capacity will drive down electricity prices. However, lower prices may lead to increased consumption during the summer in the states located in warmer regions of Australia (QLD and NT). As the study shows, most states within Australia are less responsive to price changes during summer months; moreover, their consumption patterns may change when prices are lower.

In other words, electricity consumers may tend to consume more when prices are lower, and temperatures are higher during summer months. Thus, capacity planning for an increase in RET should be aimed at the sufficient supply of electricity to meet peak demand during future summer months, while electricity optimization should be improved to balance the projected decline in winter demand across the states. On the demand side, policy options, such as the increased adoption of rooftop solar PV systems and energy-efficient AC, have great potential to reduce summer peak loads.

This study further considered how uncertainties may influence the outcome of projected electricity demand. Policy uncertainties such as changes in economic growth, energy efficiency improvements, renewable energy adoption, and changes in electricity prices, were simulated. The outcomes show that climate change mitigation strategies such as energy efficiency improvements and the adoption and increased penetration of renewable energy technologies have the potential to reduce future electricity demand because of the increase in cooling requirements up to 2050. More specifically, peak electricity demand due to cooling and heating requirements can be reduced by switching to energy-efficient AC units, while higher electricity prices can induce energy conservation because consumers may move their consumption to off-peak hours. Energy efficiency policies are important complements to the RET because they can prompt cost savings, carbon emission reductions, and decreased peak electricity demand.

Although the initial investment cost for energy efficiency measures, such as retrofitting buildings and changing to energy-efficient appliances, is high, such investment is largely offset in the long term by cost savings. Indeed, because of the short-term cost associated with energy efficiency improvements, some related state-based programs, such as energy-efficient retailer obligations, are already in place and successful in NSW, VIC, SA, and the Australian Capital Territory. Since our study shows the potential benefits of energy efficiency policies in reducing the projected increase in electricity demand due to climate change, states such as QLD, WA, and the NT need to develop state-based energy efficiency programs which include energy efficiency targets and schemes. Further, the results of our simulations show that increased penetration of renewables prompted by the government's RET and energy efficiency has the potential to reduce energy demand below 2014 levels. This reduction will in turn reduce GHG emissions from electricity generation, thereby contributing to worldwide GHG reduction and helping Australia to meet its emissions reduction obligation.

With regard to the study's empirical aspect, this study find that the stationarity of the data sets is important when estimating the impact of climate change on electricity demand. This was demonstrated by determining the model's accuracy, which involved the application of ARDL and MLR to the same model and data sets. The accuracy (in terms of MAPE) was estimated to be 0.81 ± 0.57% and 1.58 ± 1.12% for ARDL and MLR respectively. These figures imply that the ARDL model, which considers data in their stationary and non-stationary forms, presents more accurate estimates and that regression models and their long-term coefficients could be used for effective electricity demand forecasts. Thus, this study's approach is recommended for policymakers in order to ensure effective electricity forecasts and accurate generation-capacity planning.

Further, seasonal long-term coefficients can be used with energy planning tools because they can accommodate uncertainties associated with changes in end-use energy demand due to climatic factors such as temperature changes. Although the application of seasonal long-term coefficients to an energy model such as MARKAL or LEAP was not applied in this study, this option will be explored in the future. Finally, since the data were restricted to Australia, future studies should explore the application of the ARDL model to electricity demand forecasting under climate change conditions in other countries with the aim of investigating the applicability of the model and approach presented in this study.

Chapter 4: A Techno-Economic and Environmental Assessment of Long-Term Energy Policies and Climate Variability Impact on the Energy System

The previous chapter developed projections from future temperature-sensitive electricity demand estimates for Australia. The focus for this chapter, is to use estimates to develop an energy model to simulate interactions between energy policies and CV&C impacts on the energy system. Also, this chapter explores the technoeconomic and environmental implications of changes in future energy system due to CV&C impacts and policy interventions (Figure 4.1).

This chapter has been adapted into a manuscript: Emodi, N. V., Chaiechi, T., & Beg, A. R. A. (2019). A techno-economic and environmental assessment of long-term energy policies and climate variability impact on the energy system. *Energy Policy*, 128, 329-346.

Initially, this short version of this manuscript was prepared as a conference paper titled Emodi, N. V., Chaiechi, T., & Beg, A. R. A. (2018, June). A Techno-Economic and Environmental Analysis of Queensland's Transition Towards a Low Carbon Society. In *International Conference on Sustainability in Energy and Buildings* (pp. 178-188). Springer, Cham.

The conference paper focused on Queensland's pathways to a low carbon society but was improved after feedback from participant and expanded into an Australian study with climate change impact assessment in chapter 4. The conference paper is now published as a book chapter.

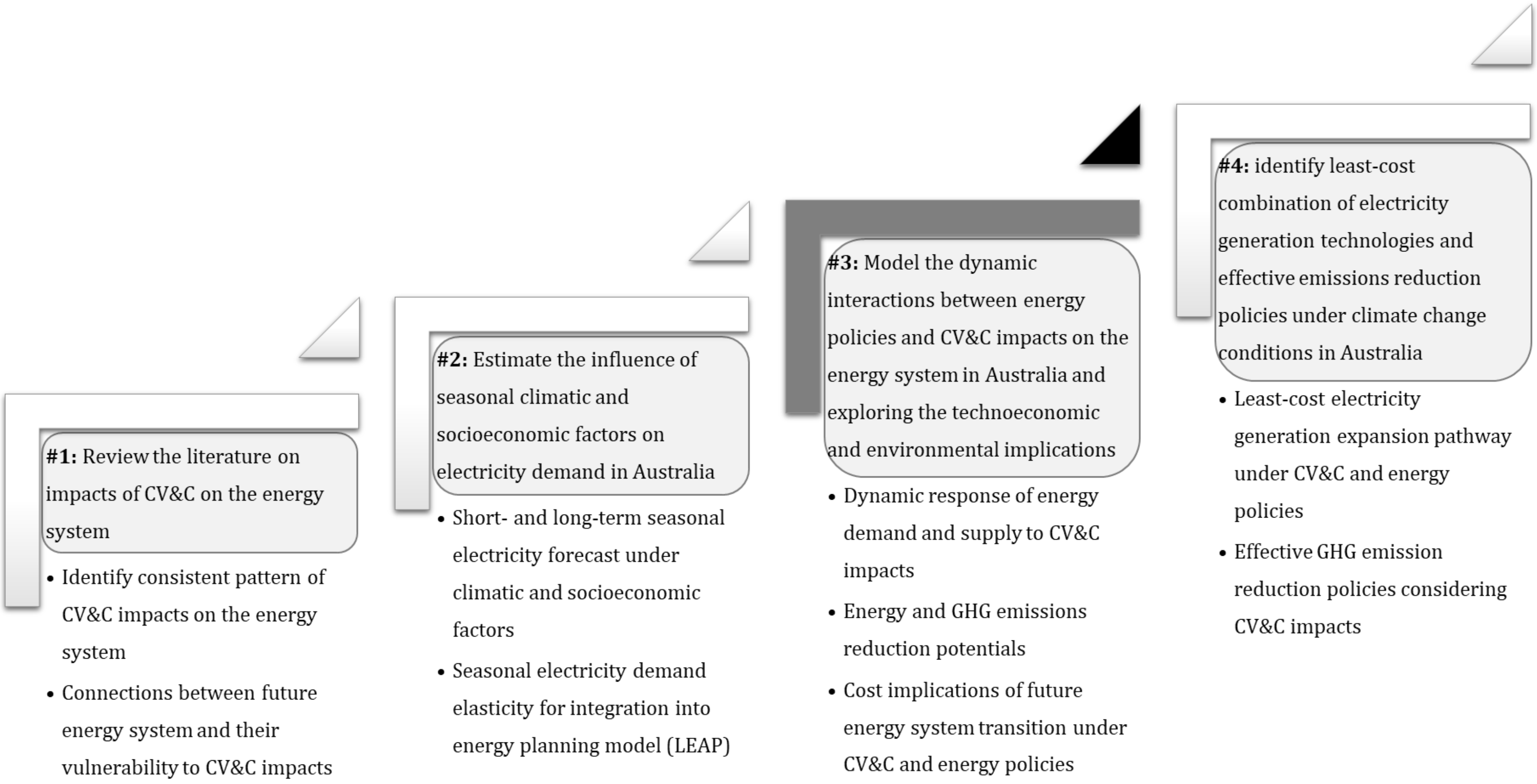

Figure 4. 1: Progress through the thesis: Research Aim #3.

4.1. Abstract

This paper examines the impact of climate variability and change (CV&C), and energy policies on the future energy system in Australia. Scenarios were developed to represent CV&C impacts and policy options, which were analysed with the Long-range Energy Alternative and Planning system for the period 2010-2050. The results indicate that although energy demand is likely to increase threefold in the business-as-usual scenario, CV&C further increases demand to 150 petajoule. A combined policy option involving modal shift and penetration of electric and hydrogen fuel cell vehicles results in a 49-53% decrease in transport fuel demand and emissions. The economic analysis reveals a substantial decline in sales revenue and increase in generation costs due to CV&C impacts. Higher renewable energy integration results in lower wholesale electricity prices across independent electricity markets. Cumulative cost-benefit analysis indicates that economic benefits increase to US$4.9 trillion in an advanced renewable energy scenario. Emissions and energy consumed increased under climatic conditions, but decreased after policy intervention. Ignoring the influence of CV&C may result in underestimation of future energy demand and installed capacity in Australia. Therefore, energy and climate policies should consider long-term economic benefits over short-term system costs.

4.2. Introduction

There is a global consensus that GHG emissions from the energy sector must be reduced and subsequently eliminated to ensure global warming is kept at a safe level (IPCC, 2015). Recently, the IPCC released a special report, which highlighted the need to reduce GHG to net zero before 2030 to limit global warming to 1.5^{o}C. The report proposed a 45% reduction in GHG emissions by 2030 and a 100% reduction by 2050; this implies transitioning about 70-85% of global fossil fuel electricity sources to renewable energy electricity sources, putting a price on carbon and increasing the diffusion of CCS. Some RETs, such as solar PV and wind energy, are expected to play an important role in transitioning the energy system and averting climate change. This is because RETs provide a sustainable means of power generation and their costs have substantially declined over the years to be competitive with generation from fossil fuel power plants (Merchant, 2018).

According to IRENA (2018), the global renewable energy capacity has increased from 1.06 TW to 2.18 TW between 2008 and 2017. This presents some optimism for the transformation of the energy system from fossil fuel dependent to renewables source, while the fuel mix for energy consumption becomes diversified. This includes the electrification and biofuel substitution in the transport sector. Although low carbon technologies, such as CCS, biofuels, and nuclear power plants, can significantly contribute to GHG mitigation, their costs vary from place to place (Keppler, 2010), are less cost-competitive (Marcacci, 2018) or are not commercialised (Letourneau, 2018, Orcutt, 2012). However, renewables are intermittent and vulnerable to climate change, as well as energy demand for space conditioning. Globally, studies show that heating demand and its fuel (e.g. natural gas) will decline while cooling demand and its fuel (e.g. electricity) will increase. In some temperate regions, this will be due to warmer summers (Parkpoom and Harrison, 2008). In contrast, colder regions are expected to have an overall decrease in energy demand due to warmer winters and reduced requirement for heating (Wang et al., 2010).

Understanding the impact of CV&C on the energy system is important, because it affects consumers, electricity companies, and policymakers by changes in expenditures, higher fuel consumption, and challenging policy development to limit global warming. To plan and manage the transition to a more sustainable energy system requires a better understanding of CV&C and its future impacts. This study demonstrates a model to quantify these changes through a combination of climate projections from a previous study, econometric estimates, and an energy modelling tool, to ensure reproducibility. Australia was used as a case study, due to its complex electrical system made up of three major and two minor energy markets that operate independently, its state-based target for renewable energy penetration but increasing emission from power generation, and because it is one of the countries most vulnerable to climate change.

Australia’s electricity sector has changed over time with the global emergence of new technologies, such as wind and battery storage systems. However, the change in Australia’s energy system is less linear and more dynamic as consumers can be at any part of the supply chain (i.e. between the generators, retailers, and customers). Most power consumers generate their own electricity from sources, such as gas, solar, wind and biomass, and supply to the grid (AEMC, 2018). This is necessary for the transition to a sustainable energy future, but raises more open-ended questions on how to safe-guard the future energy system against climate change. The political landscape of Australia's energy polices has been dramatic in recent times from the failed National Energy Guarantee (staff, 2018) to load shedding due to heatwaves (AEMO, 2018).

This study considers how the future energy system will progress based on changes in policy and explores the system's response due to CV&C. A model was developed and used to assess techno-economic and environmental implications of long-term energy policies and climate variability on the future energy system based on a scenario approach up to 2050. The remainder of this paper is arranged as follows. Section 4.2 presents a review of the literature and study contribution. Section 4.3 elaborates the methodology, including the scenario and model description. Section 4.4 presents the results and analysis, which includes the model validation and result comparison with previous studies. The discussions are presented in Section 4.5, while Section 4.6 concludes the study.

4.3. Literature Review and Study Contributions

4.3.1. Literature Review

An increasing number of studies have paid attention to the impact of CV&C on energy technologies by applying various methods. The methods range from the less complex type where GCM data are used as a proxy for CV&C impacts as applied in Carvalho et al. (2017), to the more complex method where data from GCM are used as inputs to impact models or IAM. The GCM data are retrieved from available climate change projection datasets (e.g. UKCP09 in Braun et al. (2016)), combined with emission scenarios (e.g. Seljom et al. (2011); Majone et al. (2016)) or adjust the time series to a specific linear trend for the parameter (e.g. Koch et al. (2014)). Most IAM applied in the literature varies from popular models, which have been validated to models developed for a particular study that is accompanied by a series of equations to allow for study replication.

Assessments of the impact of CV&C on the built environment are usually analysed using MLR and bottom up energy models. A large body of literature has applied MLR models where climate parameters (e.g. temperature) and economic variables (e.g. population and price) are independent variables, which are regressed with energy demand as dependent variables. The coefficients from MLR models and climate projections are used to estimate changes in future energy demand compared to the base year. Some studies applying MLR include Li et al. (2014), Chen et al. (2016) and Emodi et al. (2018). On the other hand, bottom-up energy models are developed and used to predict future energy use in buildings. Climate data are retrieved from GCMs and integrated within the simulation model. Examples include IDA ICE building simulation software used in Waddicor et al. (2016), EnergyPlus in Reyna and Chester (2017) and Rey-Hernández et al. (2018).

Some studies apply a partial equilibrium simulation model to estimate the impact of CV&C on the energy system. These include the POLES (Mima and Criqui, 2015a, Dowling, 2013a) and a combination of TIAM-WORLD[32], GEMINI-E3[33] and PLASIM-ENTS[34] used in Labriet et al. (2015). On electricity generation, hydropower and thermal power plants are affected by CV&C through impacts on generation efficiency, cooling water requirement, and variation in water inflows due to changes in evapotranspiration (Minville et al., 2009, Byers et al., 2016). Climate impacts on hydropower production are estimated using hydrological models (e.g. GEOTRANSF[35] applied in Majone et al. (2016); NAM[36], SWAT[37] and MIKE SHE[38] applied in Karlsson et al. (2016)) or simulation models used for electricity dispatch from hydropower plants (e.g. TOPKAPI[39] used in Maran et al. (2014b)).

CV&C affects cooling requirements for plants operating under Rankine and Brayton cycles and these vary from average temperature, humidity, pressure, and availability of water (Schaeffer et al., 2012). The thermal efficiencies of Rankine cycle plants, such as coal and nuclear, are affected by changes in ambient temperature

[32] TIMES Integrated Assessment Model
[33] General Equilibrium Model of International-National Interactions between Economy, Energy and Environment
[34] Planet-Simulator-Efficient Numerical Terrestrial Scheme
[35] GEOTRANSF: a continuous non-linear hydrological model
[36] Danish: Nedbør-Afstrømnings-Model
[37] Soil and Water Assessment Tool
[38] System Hydrological European
[39] TOPographic Kinematic APproximation and Integration

(Linrterud et al., 2011), while power output, fuel consumption, and efficiency of gas power plants operating under the Brayton cycle may be affected by changes in temperature and humidity (Bahrami et al., 2015). Hydrological models, such as WaterGAP3 and SWIM, have been applied to thermal electricity generation, as well as regression models used in Linrterud et al. (2011) and LEAP-WEAP[40] model applied in Sun et al. (2018).

Other electricity generation technologies include wind, which can be assessed by wind speed projections from GCM as a proxy for wind power production, or by extrapolating wind speed for a particular hub height of the turbine model being assessed (Bonjean Stanton et al., 2016). The impacts of CV&C on solar PV are estimated by developing a model of PV power generation based on the change in global radiation and the averaging by distribution of orientations and tilt angles of PV modules within a region (Wachsmuth et al., 2012, Wachsmuth et al., 2013), using potential percentage change in delta method (Panagea et al., 2014), or driving power output from GCM projected solar radiation and air temperature (Wild et al., 2015).

Despite the growing body of literature examining CV&C impacts on the energy system, there appear to be few studies examining the effect of global warming on future socioeconomic parameters, such as economic growth, energy prices, and population growth as it relates to energy use. Modelling future demand is a challenge as many studies which project future demand tend to neglect possible changes in socioeconomic variables (Brown et al., 2016), differences between sectors (Damm et al., 2017), prices, and population dynamics (Li et al., 2014). Also, studies assume a constant load factor and energy demand pattern (Parkpoom and Harrison, 2008, Byers et al., 2016), but future climatic conditions may alter consumer behaviour.

On the supply side, studies such as Van Vliet et al. (2016) and Turner et al. (2017) simulated electricity supply vulnerability to CV&C, while Hilden et al. (2018) analysed the potential cross-border impacts of climate change driven changes in hydropower potential. However, few studies have examined the rationale for power plant expansion due to increased probability of loads under future climate conditions. Even fewer studies considered the cost implication of capacity expansion and applying mitigation options to

[40] Long-range Energy Alternatives Planning System (LEAP) and Water Evaluation and Planning System (WEAP)

reduce the impact of rising temperatures (Bartos et al., 2016a). Similarly, accounting for GHG emissions from thermal plants under future climate conditions have not been well researched as few studies, such as Roux et al. (2016), only considered GHG emissions to be an applied fixed emission factor. Furthermore, literature review studies, such as Schaeffer et al. (2012) Chandramowli and Felder (2014), Bonjean Stanton et al. (2016) and Cronin et al. (2018), found few studies examining the cross-sectoral linkages and integration of CV&C impacts from both the supply- and demand-side of the energy system.

4.3.2. Study Contribution

Although the knowledge frontier has advanced over the years, studies show that developing a model which accounts for supply- and demand-side impact can address the research gaps identified in Section 2.1. This requires a model that is flexible and incorporates modification to account for changes in the energy system. In recent years, the LEAP, which is a bottom-up energy modelling tool, has been used to explore energy policies on a city, national, and global scale (Yang et al., 2017), and is flexible to incorporate econometric estimates (Mahumane and Mulder, 2016) and optimize electric supply systems with OSeMOSYS[41] (Rogan et al., 2014, Howells et al., 2011). This study takes advantage of the LEAP model's flexibility to explore the progression of future energy systems in response to policy changes and CV&C impacts up to 2050. This bottom-up model could fill knowledge gaps between power plant expansion due to cross-sectoral impacts of CV&C and cost implications to reduce the effect of global warming. The main contribution of this paper is threefold:

- Modelling the dynamic response of energy consumption sectors and electricity generation technologies to CV&C, and identifying reduction potentials of energy and GHG emissions;
- Examining the cost implication associated with future demand based on changes in climatic and socioeconomic factors, and capacity expansion of energy technologies;

[41] Open Source Energy Modelling System

- Discussing the implications for long-term policy alternatives to increase energy savings, mitigate GHG emissions, and manage the impact of CV&C;
- Deriving implications to improve on the design of coherent energy and climate policies.

4.4. Scenario and Model Approach

4.4.1. Scenario Framework

The scenario framework applied follows the Schwartz scenario-planning process (Schwarz, 1991), based on his book *The Art of Long View*, which describes the theory and practice of scenario application in organisational learning and long-term planning. The Schwartz methodology has been well-applied in literature for scenario-planning, which includes the development of frameworks for alternative energy and environmental pathways (Awopone et al., 2017b, McPherson and Karney, 2014, Ghanadan and Koomey, 2005, Nadia, 2017, Gamas et al., 2015). The scenarios intend to provide insight into potential energy pathways for Australia's energy system based on future energy policies and climate variability. The Schwartz's methodology is used to develop scenarios used in this study and they are based on the following steps:

Step 1: Defining the focal issue. Scenario development begins with defining the main issue or topic and building outward. This study's focal issue involves exploring the implications of long-term energy policies and climate variability in Australia's energy system.

Step 2: Identifying key variables. Following the identification of the focal issue, key variables are identified that may influence the energy system as well as socioeconomic, environmental and technological aspects.

Step 3: Evaluating the key variables by importance and uncertainty. The interconnected nature of the energy system and socioeconomic, environmental and technological aspects highlighted in the previous step require evaluation. This step assesses the key variables by their level of importance and uncertainty relative to the Australian energy system. Fig. 1 presents an evaluation of the key variables influencing Australia's energy system; the most critical and highly uncertain variables are located at the top-right corner, labelled 'critical uncertainties.'

Step 4: Selecting the scenario logic. The critical uncertainties presented in Figure 4.2 become the building blocks for the scenarios. This narrows the key variables and ensures that the developed policy scenarios address the focal issue and present clear policy outcomes.

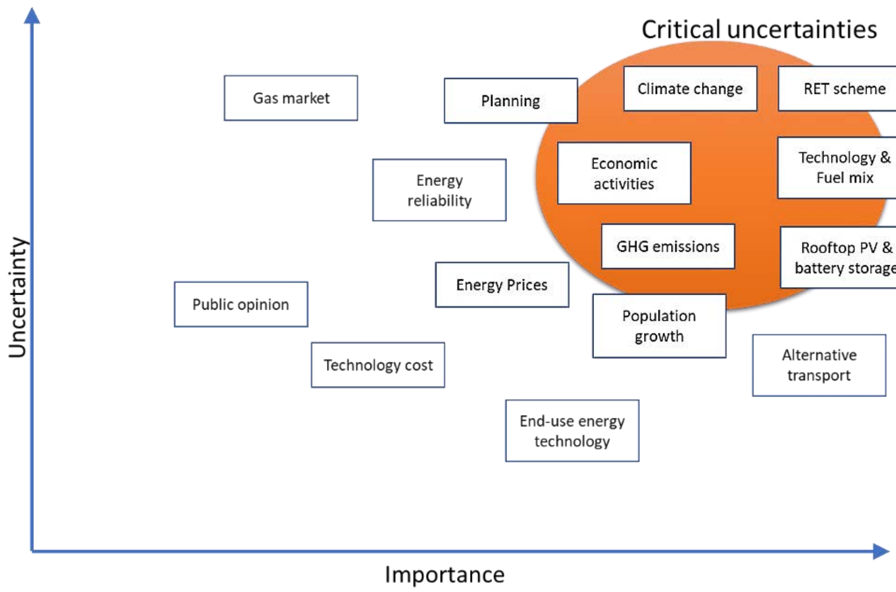

Figure 4. 2: Identifying and evaluating driving forces in Australia's energy system

As aforementioned, the scenarios developed in this study revolve around the critical issues in energy policy and CV&C. This study analysed four scenarios under policy and climate change simulations: the business-as-usual scenario (BAU), a low-carbon economy (LCE), low-grid renewable economy (LGRE) and advanced renewable economy (ARE). The scenario assumptions and policy options for the demand and supply sectors are presented in Table 4.1. The **BAU** assumes no policy measures taken to influence future energy system and historical energy intensity of 1.4% (Stanwix et al., 2015) declining to 0.8% until 2050 following BREE[42] study (Syed, 2014) and RET[43] review (Regulator, 2015c). Power generation-expansion plan follows the AEMO base neutral scenario case (Operator, 2016c).

[42] Bureau of Resources and Energy Economics
[43] Treasury's suggested energy efficiency in the 2014 Renewable Energy Target Review

Table 4. 1: Scenario assumptions and policy options for the demand and supply sectors

Scenarios	Policies and Measures	RS	CS	IN	AG	TP	TF
BAU	No policy measures taken to influence energy demand and power generation is based on AEMO's base neutral scenario						
LCE1	Application of CCS technology in industry and thermal power plants						
	Follows AEMO emission reduction scenario, but involves retirement and replacement of coal and natural gas plants with CCS-fitted supercritical and CCGT power plants						
LCE2	Coal and CCGT replaced by nuclear and solar thermal power plants; share of OCGT decreases before 2039						
	Follows AEMO emission reduction scenario, but involves retirement and replacement of coal and natural gas plants with nuclear power plants						
LCE1 & 2	Large-scale renewables such as solar PV and wind technologies with battery storage system						
	Energy efficiency increase by 20% before 2050						
	Rooftop solar PV increase by 21.7 GW before 2050						
	Energy intensity decrease each year until 2050 in the mining, manufacturing and construction industry by 1%, 1.2% and 0.2% respectively; process improvement, equipment upgrades and applying best-practice in manufacturing industry; reintroduction of mandatory energy efficiency program in mining industry; operational improvement for mining vehicles and load management						
	Energy intensity in electricity, natural gas and water services decreases by 5% annually following transition to efficient systems						
	Introduction of mandatory fuel efficiency standards for all road vehicles following DIRD Target A option of energy efficiency improvement by 75% in passenger vehicles and trucks, 80% in light commercial vehicles and 50% in buses; energy intensity for rail, air and water transport modes decreases by 25%, 33% and 30% by 2050, respectively.						
LGRE	Follows AEMO's low-grid scenario for power plant expansion capacity, but extends the plan to 2050						
	Increase in rooftop solar PV to 25 GW						
	Large-scale solar PV constrained to 6.1 GW, battery storage anticipated at 1.6 GW, wind at 13.4 GW by 2050						
	Fossil fuel power does not greatly expand as retirement of coal and natural gas plants leaves CCS-fitted supercritical coal and CCGT plants at 3.8 GW and 9.2 GW, respectively.						
	No nuclear power is introduced due to financial constraints, strong prohibitive legislation and unfavourable market conditions						
	Intensive energy efficiency program to meet shortfall in energy supply; replacement of inefficient space-conditioning technologies						
	Rising gas prices forces consumers to switch from gas space- and water-heating technology to electric heater						
	Lighting consumption decrease by 80% due to energy-labelling policy that leaves CFL and LED bulbs as the only lighting option						
	Building insulation across the states and territories increases to 90% in 2050 from their 2014 percentages						
	No CCS technology in industry, rather natural gas and biofuel become dominant fuel source						
	Industrial energy efficiency applied in LCE1&2; reduced thermal losses from heating process in furnace and boiler systems in manufacturing industries; additional energy savings in mining industry from improvements in ore and waste separation and high-pressure grinding rolls						
	Fuel switching to biofuel, gas and electricity in agriculture which reduces diesel consumption to 10% by 2050						
	Road transport efficiency from LCE1&2; shifts from bigger vehicles (i.e. SUV, Utes or tray-back) to smaller cars; share of diesel engine vehicles increases as biodiesel and ethanol-blended fuel (E10) increases to 50%; share of diesel use in railways decrease by 30% as natural gas and biofuels is introduced in 2020 and increases to 40%; aviation sector adopts 50% of its energy from biofuel						
ARE	Fossil fuel power plants are gradually retired before 2046						
	Large-scale solar PV increases to 26.6, wind to 18.4, solar-thermal to 8, geothermal to 3.8 and battery storage increases to 9.2 GW						

	Rooftop solar PV to 25.1 GW; share of solar energy for lighting increase to 40% and CFL and LED makes up 60%
	Share of electricity for space-heating increases by 60% and share of wood pallets increases to 15%, while natural gas is removed from the fuel mix; solar thermal and heat pump system is the main source for water- and space-heating
	Industrial energy efficiency policies from LCE1&2 and LGRE; biofuel followed by electricity and natural gas becomes the main fuel in 2050 in industry, agriculture, electricity, gas and water services
	Share of E10 fuel and biodiesel increases to 80% of all ICE vehicles; diesel vehicles increase to 50% in ICE vehicle category; alternative vehicle increases to 90% and ICE decreases to 10% for passenger and LCVs; for alternative vehicles, PHEV increase to 30%, EV to 34% and HFCV to 22%; buses with ICE decreases to 20% and alternative options (CNG and HFC) increases to 80%
	Mode shift from passenger to public transport decreases private car ownership to between 11-42% across the sates and territory; domestic air travel decreases by 20% due to 15% mode shift to railways and 5% to videoconferencing
RCP 4.5	Annual GHG emissions peak around 2040 and decline; climate impact on space conditioning and power plants
RCP 8.5	Annual GHG emissions continue to rise throughout the 21st century; climate impact on space conditioning and power plants

Scenarios: Business As Usual: BAU, Low-carbon economy: LCE, Low-grid renewable economy: LGRE, Advance renewable economy: ARE, Representative Concentration Pathway: RCP

Fossil fuel plants expanded to 44.4 GW, biomass and large hydro slightly expanded to 9.3 GW, and other renewables reached 27.4 GW. Economically, a shift occurred towards less energy-intensive sectors, such as the commercial services sectors, which has been a factor in the declining energy intensity. Each state's economic performance is calculated based on each respective state's economic outlook and per capita GDP, as presented in section 4.3.2.1. The population growth is based on ABS 'Series B' projection (Statistics, 2017a). According to the AEMO, the use of air conditioners will increase by 81%, and space heating use will increase by 51% by 2036 (Operator, 2016b), which is extended to 85% in this study. Further, the AEMO projects an increase in electricity and natural gas prices by 2045, by 0.9% and 0.8% respectively; leading to fuel switching by 2% for space heating and 0.4% for water heating (Operator, 2015).

The **LCE** scenario describes a country with an energy policy primarily focused on an intensive pathway towards emissions reduction through low-carbon technologies. CCS is introduced to reduce emission by 90% (Australia, 2017a). The introduction of nuclear power plants in Australia faces some legal obstacles hindering its deployment: (i) the Environmental Protection and Biodiversity Conservation Act 1999, section 140A; (ii) the Australian Radiation Protection and Nuclear Safety Act 1998, section 10; (iii) nuclear prohibitions in New South Wales, Victoria and Queensland; and (iv) large upfront capital costs (Stewart, 2017).

This scenario assumes that nuclear prohibition laws have relaxed, small modular reactors with lower capital cost are introduced in 2020, and modules are added following the simultaneous increase in demand and retirement of old coal and gas plants by 2036 and 2040, respectively. The high capital costs of both CCS and nuclear have further divided the LCE scenario into two options, in which LCE1 is the CCS-enabled scenario and LCE2 is the nuclear scenario. The two low-carbon technologies are separated due to their competing costs. Therefore, the two scenarios' outcomes will be compared in terms of electricity generation and GHG emissions, while CCS is applied to the industrial sector in the LCE1 scenario.

Energy policies modelled in the transport sector include the introduction of mandatory fuel efficiency standards for all road vehicles. Currently, Australia lacks fuel efficiency standards for road vehicles, which may result in an increase in imports of less efficient, polluting cars. A 2016 report by DIRD[44] recommended the introduction of mandatory fuel efficiency standards with three options (Australia, 2016); Targets A, B and C to reduce emissions from 2020 to 2025, from 105gCO_2/km to 135gCO_2/km. A study by the Climate Change Authority (Authority, 2014a) recommend a strong efficiency standard to reduce emissions intensity by 105gCO_2/km, while CSIRO[45] study identified a 30% energy savings by 2030 as a result of a strong fuel efficiency standard (Graham and Reedman, 2014). The Target A option is considered in the model.

The **LGRE** presents a scenario in which investment in on-grid electricity-generation plants are fewer GW than the LCE scenario (18 GW) by 2050. Building insulation will increase at 90% across the states (Statistics, 2014). The **ARE** scenario intends to achieve a clean energy society before 2050, as Australia will meet its emissions reduction target by 2030. This scenario places a greater emphasis on renewable energy sources across demand and supply sectors. It is noteworthy that the capacities in all scenarios are added endogenously in the model to maintain the system's reserve margin. The Australian electricity market's structure is maintained until 2050 across all policy scenarios, which implies that the NEM, the South West Interconnected System of Western Australia (SWIS) and Interim Northern Territory Electricity Market (I-NTEM) continue to function as a separate energy market due to transmission-related issues.

A **climate change** simulation involves the development of two climate scenarios under Representative Concentration Pathways (RCP) of 4.5 and 8.5. The RCP scenarios are somewhat consistent with socio-economic assumptions based on possible changes in human GHG emissions. This study models the RCP 4.5 and 8.5 as impacting space conditioning in residential and commercial service buildings on the demand side, and the efficiency of thermal power plants (coal, gas, or nuclear) and renewable energy (solar or wind) on the supply side. This is achieved by modelling each policy scenario to simulate a climate change scenario. Section 4.3.2.2 presents the approach used for climate change simulations.

Step 5: Evaluate the scenarios' implications. The last step in Schwartz's methodology involves an evaluation of the developed scenarios. This study used the Long-Range Energy Alternative and Planning (LEAP) system to evaluate the scenarios

[44] Department of Infrastructure and Regional Development
[45] Commonwealth Scientific and Industrial Research Organisation

and assess the techno-economic and environmental implications on Australia's energy system by 2050.

4.4.2. The Model

The LEAP system was developed by the Stockholm Environment Institute, and has been widely used since the late 1980s in public and private institutions (Heaps, 2016). This system is an energy system simulation model, which utilises an accounting framework for an energy policy analysis of demand and supply, as well as a climate change mitigation assessment (Pfenninger et al., 2014). The demand-side within the LEAP model can be represented with a macroeconomic model, while a simulation of the electricity supply can be optimised using the Open Source Energy Modelling System (Moksnes et al., 2015). Further, the LEAP model can be linked to the Water Evaluation and Planning System for water-energy planning (Dale et al., 2015). Macroeconomic modelling of the electricity sector as well as generation capacity expansion planning can effectively be modelled for the medium- to long-term.

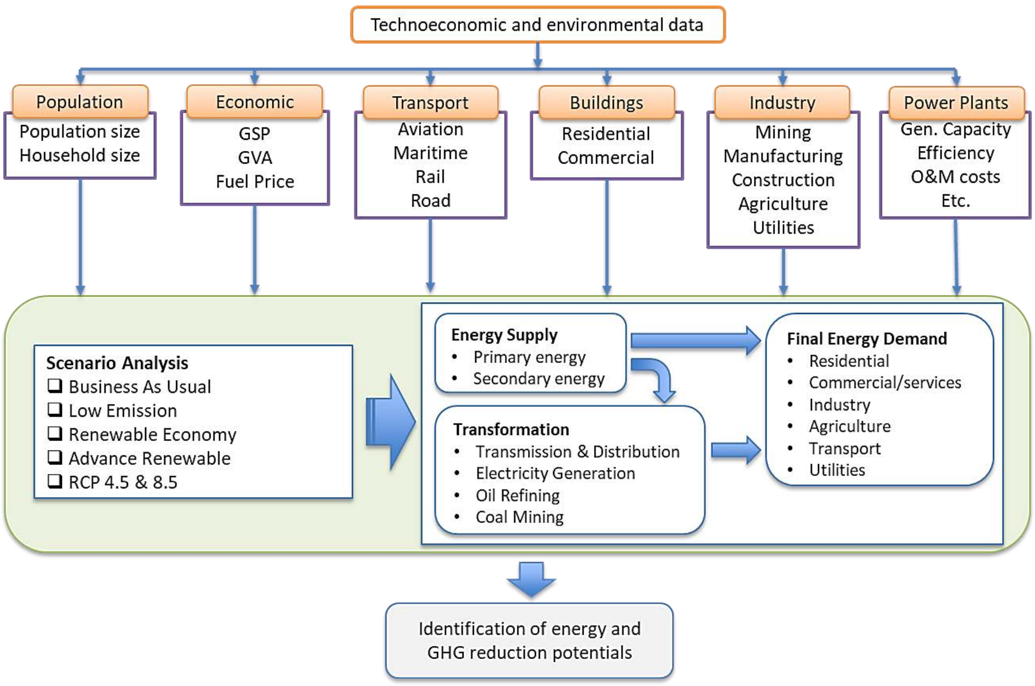

Figure 4. 3: Structure of the Australian LEAP model

The LEAP also incorporates a technology and environmental database, which describes various energy technologies' technical characteristics, costs and environmental impacts. This is useful in tracking environmental pollution at different stages of the fuel consumption chain. The technology and environmental database is sourced from the IPCC, the International Energy Agency, the US Department of Energy, the U.S. Energy Information Administration, and various academic publications. The structure of the LEAP model used is shown in Figure 4.3, while section 4.3.2.3 further describes the model. Section 4.3.2.3.2 – 4.3.2.5 present the algorithm, reserve margin, GHG emissions, cost-benefit analysis, decomposition of GHG emissions and long-term marginal electricity costs.

4.4.2.1. Sectoral Economic Growth and Data

This section demonstrates how economic growth relates to aggregate trends in sectoral structure and transport sector. The source of the data used for estimation are stated. The process is described as follows.

4.4.2.1.1. Structure of Economic Sectors

The development of a future sectoral structure for the LEAP model can either be embedded within the LEAP's overall accounting framework or calculated externally in Microsoft Excel and the results transferred to the LEAP model. This study modelled the future development pathways for the sectors analysed by combining top-down and bottom-up approaches. First, gross state product (GSP) growth rates were retrieved from state and territory government publications on the economic outlook and mid-year budget reviews. The economic forecast was selected instead of deriving historical GSP growth rates, as past economic performance does not reliably indicate future economic performance.

The GSP economic outlook for New South Wales was retrieved from (Treasury, 2018a), Victoria's from (Budget, 2018), Queensland's from (Treasury, 2018c), South Australia's from (Treasury and Finance, 2018b), Western Australia's from (Treasury, 2018b), Tasmania's from (Treasury and Finance, 2018c), and the Northern Territory's from (Treasury and Finance, 2018a). Although the GSP growth rates for most economic forecasts covered years up to 2020–2021, this study assumes the GSP growth rate predicted for 2021 continues to 2050.

Next, the evolution of the gross value added for the future time period ($GVA_{i,FY}$) were determined as shown in Equation (Eq.) below (Wu and Peng, 2016):

$$GVA_{i,FY} = GVA_{i,BY}(1 + [GSP_{FY} \times e_i]) \qquad Eq.(4.1)$$

where $GVA_{i,BY}$ is the gross value added for the *i*th industry in the base year, GSP_{FY} is the GSP growth rate in the future year (projected), and e_i is the elasticity coefficient of GSP of the *i*th industry. The values of e_i were derived from a regression of the sectoral gross value added (GVA) on the state GSP for the period of 1990–2016, using data from the Australian Bureau of Statistics (ABS) (Statistics, 2017b). Table 4.2 notes the e_i for each sector in the respective states and territories. The GVA was then evolved for the agriculture, commercial services, electricity/gas/water utilities, industry, and other sectors; Figure 4.4 and Figure 4.5 illustrate the results, with the industry noted in the left panels.

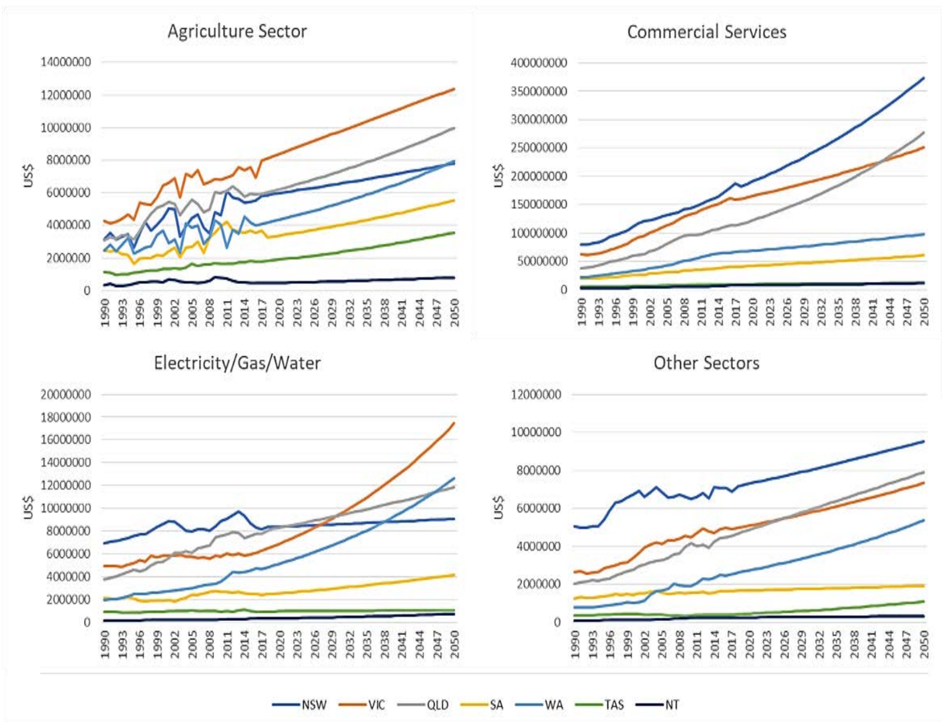

Figure 4. 4: Evolution of Sectoral Economic Growth.

(note: 1990-2014 are actual data; 2015-2050 are forecast parameters)

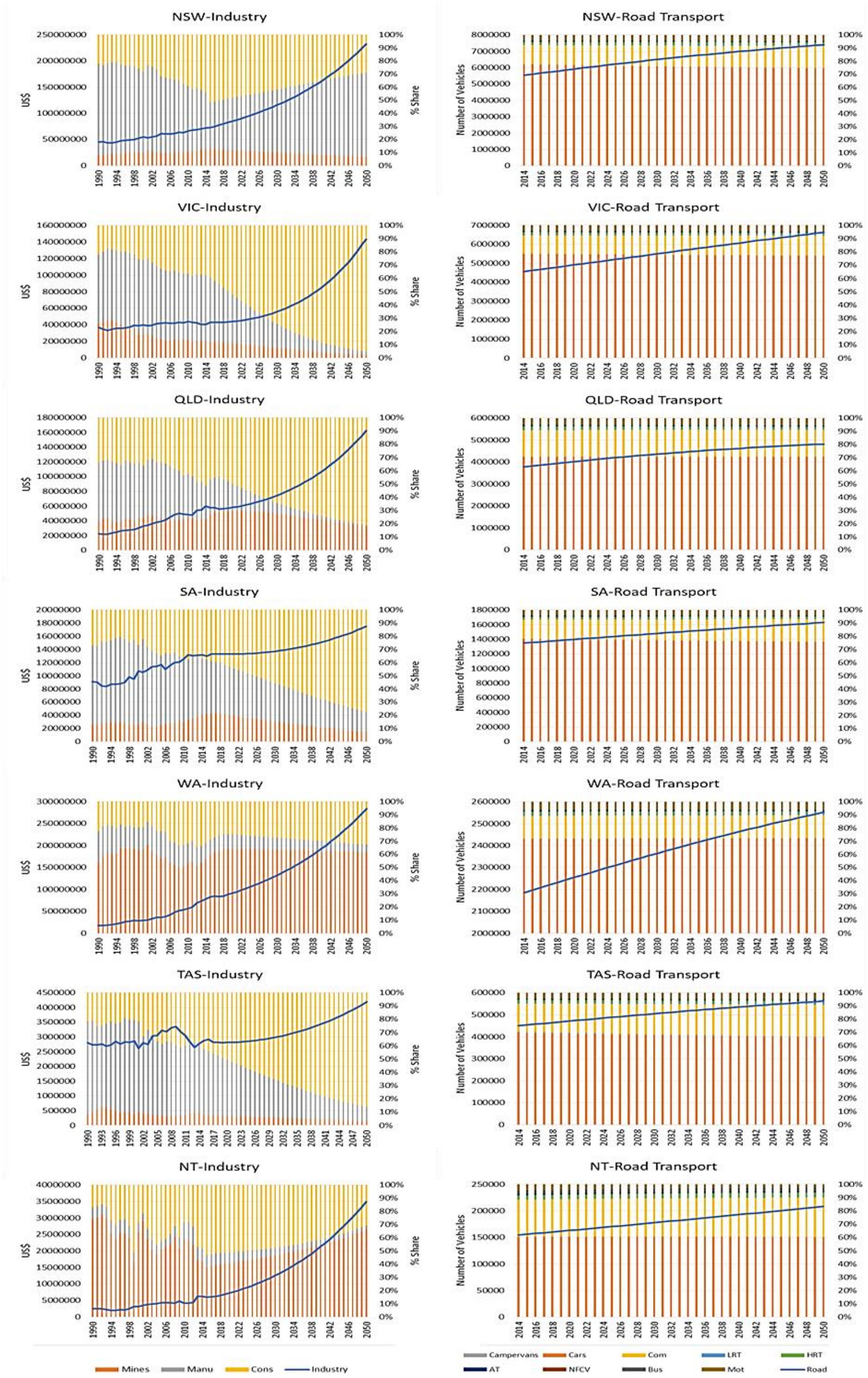

Figure 4. 5: Evolution of Industry GVA and Road Transport Vehicles (2014-2050).

Table 4. 2: Regression results for the economic sector.

	Sectorial GVA*	Agriculture	Commercial services	Mines	Manufacturing	Electric/ gas/water	Other	Construction
NSW	Constant	2.2999	0.007	-4.761	8.804	-2.025	-0.258	-2.375
	Coefficient	0.357***	0.905***	0.593**	2.029***	0.106**	0.357**	0.661*
	R2	0.78	0.73	0.41	0.57	0.28	0.70	0.82
	S.E. of Reg	0.02	0.01	0.09	0.03	0.09	0.02	0.06
	S.S. Resid	0.01	0.00	0.08	0.02	0.07	0.01	0.05
	D.W. Stat	2.13	2.29	2.12	1.78	2.03	1.95	1.99
VIC	Constant	-8.939	-1.504	29.511	0.809	3.944	-4.772	-13.384
	Coefficient	1.701***	0.508***	-1.946**	-1.701***	1.146**	0.445**	4.460***
	R2	0.57	0.80	0.39	0.40	0.66	0.29	0.85
	S.E. of Reg	0.06	0.01	0.05	0.02	0.02	0.03	0.03
	S.S. Resid	0.05	0.00	0.05	0.00	0.01	0.02	0.02
	D.W. Stat	1.89	1.64	2.10	1.93	2.26	1.82	2.10
QLD	Constant	1.513	0.018	-1.438	1.135	0.955	0.032	-0.586
	Coefficient	0.468*	0.812***	0.514*	-1.914***	0.350**	1.205***	3.046**
	R2	0.89	0.64	0.47	0.60	0.78	0.46	0.27
	S.E. of Reg	0.07	0.01	0.07	0.03	0.02	0.02	0.02
	S.S. Resid	0.06	0.00	0.05	0.02	0.01	0.01	0.01
	D.W. Stat	1.85	2.04	1.83	2.04	1.80	1.97	2.03
SA	Constant	-1.290	0.015	30.872	2.753	-6.317	4.654	-5.944
	Coefficient	0.726***	0.538***	-1.055**	-0.873*	0.722**	0.196*	1.262***
	R2	0.79	0.48	0.96	0.78	0.31	0.86	0.64
	S.E. of Reg	0.03	0.01	0.06	0.03	0.04	0.07	0.09
	S.S. Resid	0.02	0.00	0.05	0.02	0.04	0.06	0.08
	D.W. Stat	2.06	2.15	2.04	1.68	1.98	2.15	2.06
WA	Constant	8.510	0.025	-18.793	-0.341	5.879	-2.744	-9.805
	Coefficient	0.676***	0.393**	1.238**	0.518**	-1.014**	0.759***	1.591*
	R2	0.44	0.29	0.61	0.38	0.28	0.58	0.22
	S.E. of Reg	0.06	0.01	0.05	0.06	0.03	0.06	0.04
	S.S. Resid	0.04	0.00	0.04	0.04	0.01	0.05	0.03
	D.W. Stat	2.03	1.84	2.00	1.93	1.68	1.54	1.93
TAS	Constant	-0.883	0.065	13.079	2.852	6.518	1.965	-10.493
	Coefficient	1.057***	0.278***	-0.565***	-1.597**	0.193*	1.485**	1.573**
	R2	0.55	0.49	0.77	0.82	0.63	0.74	0.87
	S.E. of Reg	0.04	0.01	0.07	0.04	0.04	0.04	0.08
	S.S. Resid	0.04	0.00	0.05	0.04	0.03	0.03	0.07
	D.W. Stat	2.37	2.02	1.99	1.77	1.52	1.89	2.09
NT	Constant	6.813	-0.956	-8.887	-2.469	6.428	-0.622	-22.601
	Coefficient	0.357*	0.263***	1.425*	0.399*	-0.542***	0.144*	3.074**
	R2	0.67	0.24	0.79	0.33	0.47	0.48	0.89
	S.E. of Reg	0.05	0.02	0.03	0.02	0.03	0.04	0.08
	S.S. Resid	0.03	0.00	0.01	0.01	0.02	0.04	0.07
	D.W. Stat	1.66	1.87	1.59	1.71	2.19	1.63	2.03

Note: The regression results were estimated separately for each state (i.e. state-by-state basis). Model for the regression: **Dependent variable = coefficient * In(state/territory GSP) + constant.* Sample size: 27 datasets (1990-2016) for GSP and GVA by sector for each state and territory were retrieved from (ABS) (Statistics, 2017b).

4.4.2.1.2. Structure of the Transport Sector

The transport sector's evolution was based on the evolution of per capita GSP, which was estimated using the GSP forecast and population projections. The GSP's future development path was developed using a top-down approach, as follows:

$$GSP_{FY} = GSP_{BY}(1 + [GSP_{FY} \times \theta]) \qquad Eq. (4.2)$$

where all variables are as previously defined, and θ is a parameter that determines the speed of decline for a logistic growth curve, and is state/territory specific. This study's values of θ are: 1.4 for New South Wales, 0.9 for Victoria, 1.5 for Queensland, 0.8 for South Australia, and 1.2 for Western Australia; Tasmania and the Northern Territory both had values of 1.0. The population projections were retrieved from ABS population projections (Statistics, 2017a). The GSP forecast and population projection were used to calculate the per capita GSP, and Fig. A.2.1 displays the results.

Following the literature (Medlock III and Soligo, 2002, Dargay et al., 2007, Mahumane and Mulder, 2016), this study considered the road transport sector's evolution as primarily determined by the per capita GSP, while fuel prices are considered a second-order effect. Due to data availability, the total passenger travelled per kilometres (km) for road transport was retrieved from the Bureau of Infrastructure, Transport and Regional Economics (BITRE) (Bureau of Infrastructure, 2015). We then use the total passenger travelled per km as a proxy for the evolution of the road transport sector determined by the per capita GSP, as follows:

$$V_{FY} = V_{BY} \times \left(1 + \left[\frac{e}{pGSP_{BY}}\right]\right) \qquad Eq. (4.3)$$

where V_{FY} and V_{BY} are the number of road transport vehicles in the future and base years, respectively; e is the elasticity of the change in the road transport vehicle fleet under the influence of economic development (Table 4.3 displays the details); and $pGSP_{BY}$ is the per capita GSP in the base year, calculated from Eq. (4.2).

Further, Figure 4.6 presents the results of the road transport sector's evolution, with transport noted in the right panels. The parameter for buses within the road transport fleet was extended to light and heavy rigid trucks and articulated and non-freight-carrying trucks. Other transportation sectors also employed the same approach presented in Eq. (4.3), using BITRE infrastructure data for the rail (Bureau of Infrastructure, 2017c), maritime (Bureau of Infrastructure, 2017a) and aviation (Bureau of Infrastructure, 2017b) sectors.

Table 4. 3: Estimated results for the Road, Rail, Maritime and Aviation Transport.

	Total Passenger travelled per km*	Passeng. Vehicles	Commer. Vehicles	Motorcycles	Buses	Rail (Passeng.)	Road (Freigt)	Rail (Friegt)	Maritime	Aviation
NSW	Constant	10.661	15.157	-0.251	-0.025	3.595	0.038	-0.491	24.883	3.975
	Coefficient	0.591**	-0.799***	0.173***	0.620**	-1.123**	-0.833**	1.299**	-0.142**	0.496***
	R2	0.58	39	0.47	0.33	0.28	0.52	0.97	0.25	0.68
	S.E. Reg	0.01	0.01	0.03	0.01	0.03	0.02	0.03	0.09	0.04
	S.S. Resid	0.00	0.00	0.02	0.00	0.01	0.00	0.03	0.05	0.04
	DW Stat	1.79	1.63	1.60	2.30	2.20	2.37	1.65	2.08	1.98
VIC	Constant	5.704	16.299	-2.060	-1.483	-0.291	0.007	-3.589	26.590	-2.678
	Coefficient	0.432**	-0.438**	0.174***	0.111*	0.917**	0.915***	0.468*	-0.246**	1.866***
	R2	0.33	0.82	0.73	0.97	0.78	0.53	0.87	0.27	0.25
	S.E. Reg	0.01	0.01	0.02	0.03	0.03	0.02	0.06	0.02	0.03
	S.S. Resid	0.00	0.00	0.01	0.02	0.01	0.00	0.05	0.01	0.02
	DW Stat	1.74	1.61	1.92	1.76	1.68	2.01	2.11	2.08	1.97
QLD	Constant	1.30	1.130	-1.964	-5.629	3.801	3.048	1.138	3.396	-2.291
	Coefficient	0.417**	0.223**	0.230***	0.534*	0.332**	1.064***	1.541***	0.494**	1.469*
	R2	0.88	0.60	0.74	0.24	0.85	0.89	0.68	0.47	0.68
	S.E. Reg	0.01	0.02	0.04	0.04	0.03	0.02	0.03	0.04	0.01
	S.S. Resid	0.00	0.01	0.03	0.03	0.03	0.01	0.03	0.04	0.00
	DW Stat	1.87	1.95	1.86	2.13	1.69	1.73	2.04	1.88	2.21
SA	Constant	2.378	12.109	-2.412	1.747	4.554	9.372	-5.659	22.597	-1.534
	Coefficient	0.113*	-0.561**	0.331***	0.546**	0.313***	-1.390***	1.297*	-0.163*	1.375**
	R2	0.71	0.38	0.57	0.45	0.64	0.23	0.33	0.29	0.48
	S.E. Reg	0.02	0.02	0.03	0.02	0.03	0.02	0.07	0.07	0.04
	S.S. Resid	0.00	0.00	0.02	0.01	0.03	0.01	0.06	0.06	0.03
	DW Stat	1.97	1.52	1.80	1.59	1.73	1.67	1.84	2.11	1.64
WA	Constant	4.206	1.465	-2.046	3.199	-0.782	-5.317	-0.023	23.522	-8.589
	Coefficient	-0.296***	-0.398***	0.368***	0.194***	-1.865**	1.254***	2.242**	-0.664***	0.935*
	R2	0.84	0.20	0.41	0.26	0.67	0.82	0.29	0.82	0.80
	S.E. Reg	0.02	0.02	0.03	0.02	0.09	0.02	0.07	0.08	0.04
	S.S. Resid	0.01	0.00	0.02	0.01	0.08	0.02	0.06	0.07	0.03
	DW Stat	2.02	1.85	1.87	1.65	1.90	1.89	1.68	1.70	2.17
TAS	Constant	6.210	0.033	-2.462	8.267	NA	NA	NA	26.472	-2.919
	Coefficient	-0.655***	-0.731***	0.292**	-0.163*	NA	NA	NA	-4.748*	1.907**
	R2	0.86	0.48	0.27	0.72	NA	NA	NA	0.38	0.83
	S.E. Reg	0.01	0.01	0.09	0.02	NA	NA	NA	0.02	0.06
	S.S. Resid	0.00	0.01	0.08	0.01	NA	NA	NA	0.01	0.04
	DW Stat	1.59	1.83	2.09	1.53	NA	NA	NA	1.73	2.24
NT	Constant	4.376	10.283	-2.217	2.938	NA	NA	NA	0.284	3.141
	Coefficient	-0.162*	-0.273***	0.390**	0.169*	NA	NA	NA	-11.113**	0.142*
	R2	0.86	0.22	0.17	0.27	NA	NA	NA	0.58	0.71
	S.E. Reg	0.02	0.02	0.04	0.03	NA	NA	NA	0.05	0.06
	S.S. Resid	0.01	0.01	0.03	0.02	NA	NA	NA	0.05	0.05
	DW Stat	1.62	1.52	1.50	1.78	NA	NA	NA	2.16	1.51

Note: The regression results were estimated separately for each state (i.e. state-by-state basis). Model for the regression: **Dependent variable = coefficient * In(state/territory GSP) + constant.* Sample size: 26 datasets (1990-2016) for GSP by state and territory were retrieved from ABS (Statistics, 2017b), population projections from ABS (Statistics, 2017a), and total passenger travelled by transport mode for each state and territory were retrieved from BITRE for road (Bureau of Infrastructure, 2015), rail (Bureau of Infrastructure, 2017c), maritime (Bureau of Infrastructure, 2017a) and aviation (Bureau of Infrastructure, 2017b) transport sector.

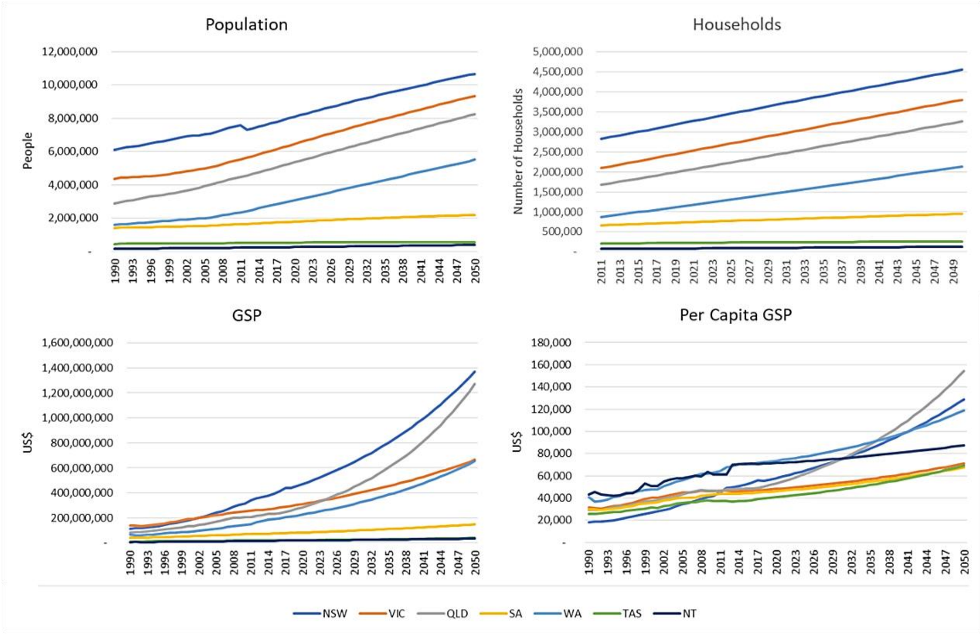

Figure 4. 6: Population [a], Households [b], GSP and Per Capita GSP forecast.

Source: [a]ABS (Statistics, 2017a), [b]ABS (Statistics, 2015a)

4.4.2.2. The LEAP Model Modification for Climate Change Analysis

Although the LEAP model has not been previously used in a climate change impact analysis to the best of our knowledge, the model's flexibility allows for some useful modifications to achieve our aim, explained below.

4.4.2.2.1. The Impact of Cooling and Heating Degree Days on Residential and Commercial Services' Energy Demands

Studies on climate change's impact on energy demands have revealed that changes or increases in energy consumption patterns primarily occur due to the global increase in air temperature. Further, demand-side observations within these climate impact studies have found that rising temperatures have a more severe impact on the residential and commercial service sectors. Although studies have also found that other such climate-related variables as precipitation and wind speeds can alter energy demand, literature has largely identified changes in temperature to demand as the leading cause. The changes in temperature to demand are calculated by the cooling degree days (CDD) and heating degree days (HDD). Few studies in literature have suggested that degree days are a less reliable indicator in predicting changes in electricity demand. However, climate change impact literature focusing on the energy system has increasingly and continually relied on degree days, including such organisations as the U.S.' EIA[46] and AEMO in their planning and forecasting reports[47]. This study applied the (Emodi et al., 2018)-estimated CDD and HDD elasticities and future CDD and HDD values for Australian states under the RCP 4.5 and RCP 8.5 scenarios until 2050.

This study's LEAP model splits space conditioning into two categories: air conditioners and space-heating technologies. On the one hand, as air conditioners are powered only by electricity and exist for cooling purposes, the CDD elasticity and its future values were used. On the other hand, space-heating technology is further divided based on fuels, as electric, natural gas and wood. The temperature limit used to calculate CDD and HDD in (Emodi et al., 2018) study ranged between 12–18°C for HDDs and 18–24°C for CDDs, depending on the Australian state or territory. The LEAP model considers changes in economic growth (GDP), improvements in the efficiency of cooling and heating technology and changes in energy prices based on the state and territory. The calculation follows (Dowling, 2013b), who used the POLES (Prospective Outlook for the Long-term Energy System) model, but this study modifies this approach using the LEAP model.

Residential cooling demand, including climate impact, was calculated as follows:

$$RCD_{CI} = RCD \times \left(\frac{CDD_{el} \times CDD_{FY}}{CDD_{BY}}\right) \times AC_{BY} \times AC_{FY} \qquad Eq. (4.4)$$

where RCD_{CI} is the residential cooling demand with climate impact, RCD is the residential cooling demand without climate impact, CDD_{el} is the elasticity of CDD to electricity demand, CDD_{FY} is the value of CDD in the future year, CDD_{BY} is the value of CDD in the base year, AC_{BY} is the penetration rate of air conditioners in the base year, and AC_{FY} is the penetration rate of air conditioners in the future year.

The commercial services' cooling demand was calculated as follows.

$$CSCD_{CI} = CSCD \times \left(\frac{CDD_{el} \times CDD_{FY}}{CDD_{BY}}\right) \qquad Eq. (4.5)$$

[46] https://www.eia.gov/energyexplained/index.php?page=about_degree_days
[47] http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEFR/2016/Forecasting-Methodology-Information-Paper---2016-NEFR---Final.pdf

where $CSCD_{CI}$ is the commercial services' cooling demand with climate impact, $CSCD$ is the commercial services' cooling demand without climate impact, CDD_{el} is the elasticity of CDD to electricity demand, CDD_{FY} is the value of CDD in the future year, and CDD_{BY} is the value of CDD in the base year.

Residential and commercial services' heating demand is calculated with climate impacts as follows:

$$HD_{CI} = HD \times \left(\frac{HDD_{el} \times HDD_{FY}}{HDD_{BY}}\right) \times HT_{BY} \times HT_{FY} \qquad Eq. (4.6)$$

where HD_{CI} is the heating demand with climate impact, HD is the heating demand without climate impact, HDD_{el} is the elasticity of HDD to electricity demand, HDD_{FY} is the value of HDD in the future year, HDD_{BY} is the value of HDD is the base year, HT_{BY} is the penetration rate of space-heating technology in the base year, and HT is the penetration rate of space heating technology in the future year. The base year air conditioner and heater penetration rate was retrieved from ABS data on environmental issues (Statistics, 2014). An AEMO (Operator, 2016b) study projected the future air conditioning penetration rate to increase to 80%, while heaters were anticipated to increase by 59% in 2036. This study assumes a further increase to 85% penetration for air conditioners and a 60% penetration for heaters by 2050.

4.4.2.2.2. The Impact of Climate Change on Electricity Generation

This study examined the impact of climate change on thermal power plants and solar PV systems. The thermal power plants analysed include coal-fired, supercritical and PC, natural gas CCGT and OCGT, and nuclear power plants. Hydroelectric and wind power plants were not analysed due to data availability. The model for climate change's impact on electricity generation focuses on impacts of both power plant process efficiency and maximum availability.

4.4.2.2.2.1. Thermal Power Plants

The literature has indicated that changes in average temperatures affect thermal power plants' efficiency as well as output. Regarding nuclear power plants, (Linnerud et al., 2011) found that a 1^0C increase in temperature decreases the power supply from nuclear power plants by 0.5% by affecting its thermal efficiency. Similarly, (Durmayaz and Sogut, 2006) estimated that a 1^0C increase in coolant temperatures in a pressurised-water nuclear reactor decreases thermal efficiency by 0.12% and power output by 0.45%. A study by (van Aart F et al., 2004) noted that a 1^0C increase in coolant yields a decrease in efficiency of approximately 0.17%, 0.24% and 0.27% in coal, gas and CCGT power plants, respectively. Further, (Colman, 2013) found that a 1^0C increase in air temperature decreases plant efficiency by 0.01%, while a 1^0C increase in water temperature correlates with a 0.02% decrease in plant efficiency. (Morrill et al., 2005) demonstrated that a 1^0C increase in air temperature increases stream water temperature from 0.6^0C to 0.8^0C; the study used a factor of 0.8 for the air-to-water factor.

This study extends the approach applied in (Dowling, 2013b) by the analysing temperature changes' impacts on power plants' thermal efficiency and maximum availability. First, the thermal efficiency was calculated, as follows:

$$PE_{CI} = PE \times \left(1 - \left[Ef_I \times AWF \times \frac{(CDD_{FY} - CDD_{BY})}{365}\right]\right) \qquad Eq. (4.7)$$

where PE_{CI} is the thermal power plant efficiency with climate impact, PE is the thermal power plant efficiency without climate impact, Ef_I is the efficiency impact per degree, AWF is the air to water factor (0.8), CDD_{FY} is the cooling degree day values in the future year, CDD_{BY} is the base year's cooling degree day values, and 365 is the number of days in a year.

The thermal power plant's maximum availability was calculated as follows:

$$MA_{CI} = MA - ([PE_{CI} - PE] \times 10000) \qquad Eq. (4.8)$$

where MA_{CI} is the maximum availability with climate impact, MA is the maximum availability without climate impact, and 10,000 is the conversion factor for this study's process efficiency.

4.1.1.1.1.1 Solar PV Panels

The electrical efficiency of silicon-based (commercial grade) solar PV can be affected by temperature changes. Further, (François et al., 2016) identified solar irradiance and air temperature as the main dependent factor affecting solar PV efficiency; (Jerez et al., 2015) found that an increase in air temperature under the RCP 4.5 and 8.5 scenarios decreased the solar PV-generated output by 6% and 10%, respectively; (Ma et al., 2016a) found a 10% to 20% increase in solar PV economic costs due to the increase in average air temperature and solar irradiance; and (Skoplaki and Palyvos, 2009) reveal a linear relationship between temperature and solar PV efficiency, as follows:

$$\eta_c = \eta_{Tref}\left(1 - \beta_{ref}\left[T_c - T_{ref}\right]\right) \qquad Eq. (4.9)$$

where η_c is the solar PV module's electrical efficiency; η_{Tref} is the electrical efficiency of the solar PV module at a referenced condition; β_{ref} is the temperature coefficient at a referenced condition, which PV manufacturers typically provide as 0.0045; T_c is the module-operating temperature in the current conditions; and T_{ref} is the reference temperature.

Following Dowling (2013b), the relationship is modified in Eq. (4.10), as temperature is calculated by summing the daily temperature in a year, as shown below:

$$\eta_c = \eta_{Tref}\left(1 - 0.0045 \times \frac{\left[DD_{FY} - DD_{BY}\right]}{365}\right) \qquad Eq. (4.10)$$

where DD_{FY} is the sum of the daily temperature in a future year, and DD_{BY} is the sum of the daily temperature in the base year. The solar PV plant's maximum availability is calculated as follows:

$$MA_{CI} = MA - \left(\eta_c - \eta_{Tref}\right) \qquad Eq. (4.11)$$

where MA_{CI} is the maximum availability with climate impact, MA is the maximum availability without climate impact, and other variables are as previously defined. The η_c and MA_{CI} values were input into the LEAP model as process efficiency and maximum availability, respectively, depending on the climate change scenario (RCP 4.5 or 8.5). This study acknowledges that changes in other climate factors—such as wind, relative humidity, or solar irradiance—may alter power plants' energy demands, efficiency and availability. However, this study did not capture these climatic factors due to a lack of data, but should be considered in future studies.

4.4.2.3. Structure of the LEAP Model and Data Sources

This study develops a multi-regional energy model to access the techno-economic and environmental implications of various energy and climate policy scenarios. The model includes modules for demand, transformation and resources. The demand module contains seven sectors: residential; commercial services; industry; agriculture; electricity, gas, water and sewage services; transport; and others. The transformation module includes transmission and distribution, electricity generation, oil refining, coal mining, coal-seam gas, natural gas and liquefied petroleum gas (LPG) production. The resource module is comprised of primary and secondary energy resources, which the transformation branch uses to supply energy to the demand branch.

The regional energy model intends to simulate the Australian energy system, with seven states: New South Wales, Victoria, Queensland, South Australia, Western Australia, Tasmania and the Northern Territory. The seven states are modelled as independent, and they share the energy resources available within their borders. The regional energy model was developed to allow the inter-regional trading of energy commodities, such as electricity, natural gas and gasoline, among others. However, inter-regional trade follows the *shortfall/surplus* rule, whereby a region imports energy commodities from other regions when a shortfall of energy commodities occurs, and they export any surplus energy commodities to other regions. However, if energy production is insufficient to meet domestic and export requirements, then the usage rule follows a domestic priority, whereby energy commodities are not exported from the region. In a situation with surplus energy commodities, the product is exported out of the model (Australia) to the international market. In contrast, when a shortfall occurs, and no region can meet demand, the commodity is imported from overseas. The model's structure and data source are described below.

4.4.2.3.1. Demand Module

4.4.2.3.1.1. Residential Sector

Five end-use technologies were specified in the residential sector: space conditioning, water heating, appliances, lighting and cooking. The structure was modelled following works by (Statistics, 2014, Science, 2015, Program, 2016, Statistics, 2007). The end-use technologies were further subdivided into their main technologies that not only consume energy commodities at a running cost—such as electricity, natural gas, wood, or LPG—but also emit environmental emissions. Energy intensity data for the respective technologies were retrieved from the Residential Energy Baseline Study (Science, 2015), and their intensities were compared with energy intensities published by the Office of the Chief Economist (OCE) (Economist, 2016) for Australia's residential sector by state and fuel type.

Each household technology's running cost was calculated using the intensities and online appliances running cost calculator from Ergon Energy (Energy, 2018b). It is noteworthy that each household technology and end use were modelled specific to the residential sector in the seven Australian states and territory. Data for the Australian Capital Territory were merged with data from New South Wales to ensure consistency. The number of persons living in a household, number of households and family projections for each Australian state and territory follow the Australian Bureau of Statistics (ABS) (Statistics, 2015a), while the income per capita was retrieved from (Statistics, 2017b).

4.4.2.3.1.2. Commercial Services

The commercial services are comprised of subsectors—such as hospitals, hotels, law courts, offices, public buildings, retail outlets, schools and tertiary institutions—following a study by the now defunct Department of Climate Change and Energy Efficiency (Efficiency, 2012). The subsectors were combined as a single commercial service sector due to data limitations. The end-use technology includes space conditioning, lighting, vertical transport (i.e. elevators), information technology equipment, domestic hot water, kitchen/cooking, other electrical and gas processes, and other energy. The energy intensity data from (Efficiency, 2012) were initially used, but the commercial sector's energy intensity data were further retrieved from (Economist, 2016) due to data limitations. The commercial sector's activity was derived from the gross value added for the respective subsectors, and the data were retrieved from ABS (Statistics, 2018).

As with the residential sector, the final energy data used by the respective technologies were also modelled with the environmental emissions associated with the consumption of energy commodity. The running cost for each end-use technology in the commercial services sector was calculated using consumption and expenditures data for electricity, natural gas and other energy inputs by selected Australian industries and as published by the ABS (Statistics, 2016a). As data for the industry's expenditure on energy commodity were not available each state, the percentage share of each state's GVA for commercial services was used as a determinate for energy expenditures.

4.4.2.3.1.3. Industry and Other Sectors

This study defines the industry sector to include the mining, manufacturing and construction industries, while agriculture, electricity, gas and water services were modelled separately from the industry sector. Due to technologies' lack of available data, the share of final energy intensities by energy type was used (Energy, 2017b). Each sector's activity is represented by the aforementioned respective industries' GVA, and this data was retrieved from ABS (Statistics, 2018). Energy consumption expenditures were also calculated from (Statistics, 2016a), and the final energy intensities were noted from each industry. Data for industries in the utility sector (i.e. electricity generation and towns' gas supply, water distribution and waste disposal services) were combined as one sector, or electricity, gas, and water services.

4.4.2.3.1.4. Transport Sector

The transport sector was modelled to cover all modes pertaining to transportation, which include road, rail, maritime, aviation and other transport/postage services. Road transportation includes passenger vehicles, camper vans, light commercial vehicles, light and heavy rigid trucks, articulated trucks, non-freight carrying trucks, buses and motorcycles. The structure of the road transport mode by state and vehicle was derived from the ABS' motor vehicle census (Statistics, 2016b) and motor vehicle use survey (Statistics, 2015b). The rail transportation mode is comprised of passenger and freight transport, and the data was retrieved from the Bureau of Infrastructure, Transport and Regional Economics (BITRE) (Bureau of Infrastructure, 2017c).

Maritime transport mode data, which includes coastal and international bunkers, were also retrieved from the BITRE (Bureau of Infrastructure, 2017a). The aviation transportation mode includes passenger (domestic and international flights) and freight/postal services, and data regarding the industry's activities and structure were retrieved from the BITRE (Bureau of Infrastructure, 2017b). Other transport and postage services' structures were calculated from ABS (Statistics, 2017b), while data for each transport mode's energy intensities were calculated from the OCE (Energy, 2017b), with cost derived from ABS (Statistics, 2016a).

4.4.2.3.1.5. Transformation and Resource Module

The transformation module is made up of seven sectors: transmission and distribution, electricity generation, crude oil refining, coal and uranium mining, coal-seam gas, natural gas and LPG production. Transmission and distribution loss data were retrieved from the International Energy Agency (Agency, 2017), and electricity and natural gas data was obtained from ABS (Statistics, 2002). Data for crude oil refineries, coal mines and coal-seam gas, natural gas, LPG production and Australia's energy resources were retrieved from the Australian Energy Assessment study (Australia and BREE, 2014), the OCE (Economist, 2017), and World Nuclear Association (Association, 2017). Data for electricity generation were retrieved from multiple sources, including the Fuel and Technology Cost Review (ACC, 2014), the AEMO (Operator, 2018a), Clean Energy Regulator (Regulator, 2018b) and OCE (Energy, 2017b).

4.4.2.3.2. The LEAP Algorithm

The LEAP model applies a framework to endogenously calculate energy consumption, transformation (transmission and distribution, electricity production, oil refining, coal and uranium mining, coal-seam gas, and LPG and natural gas production), carbon emissions, total sector costs, a cost-benefit analysis and, more recently, a decomposition analysis.

A sector's total energy consumption is calculated as follows (Feng and Zhang, 2012):

$$EC = \sum_{f}\sum_{i}\sum_{j} AL_{f,t,i} \times EI_{f,t,i} \qquad Eq.(4.12)$$

where TC is a given sector's aggregate energy consumption, AL is the activity level, EI is the energy intensity, f is the type of fuel consumed, t is the technology, and i is the sector.

The net energy consumption in the transformation module is calculated as follows (Zhang et al., 2011):

$$ET_s = \sum_{m}\sum_{t} ETP_{t,m} \times \left(\frac{1}{f_{t,m,s}} - 1\right) \qquad Eq.(4.13)$$

where ET is the net energy consumption, ETP is the energy transformation product (e.g. electricity, petrol, diesel, etc.), f is the energy transformation efficiency, s is the type of primary energy, m is the equipment, and t is the type of secondary energy.

In the transmission and distribution module, the required domestic and output fuels are mapped directly into the module's input fuels; the total domestic fuels are then reduced by the module's outputs and increased by its inputs. For each process p (Emodi et al., 2017),

$$INPUT_P = {}^{OUTPUT_P}/_{EFFICIENCY_P} \qquad Eq.(4.14)$$

and for a transmission and distribution module,

$$EFFICIENCY_P = 1 - LOSSES_P \qquad Eq.(4.15)$$

where *INPUT* is the feedstock fuel, *OUTPU*T is the production output (e.g. electricity, or a refinery or mining product) and *EFFICIENCY* is the efficiency of the electricity-generating plant, refinery or mines.

The LEAP model calculates the capacity addition for an endogenous capacity expansion in the electricity-generating module as follows (Awopone et al., 2017b):

$$CA_{ED} = D_p(RPM - RM) \qquad Eq.(4.16)$$

where CA_{ED} is the endogenous capacity added to the electricity generation mix, D_p is the peak requirement, PRM is the planning reserve margin and RM is the reserve margin before the generation capacity is added. The RM is determined by

$$RM = {(C - D_p)}/{D_p} \qquad Eq. (4.17)$$

while D_p is determined by

$$D_p = {ED}/{(LF \times 8760)} \qquad Eq. (4.18)$$

where ED is the required energy, LF is the load factor and C is the capacity factor before addition, calculated as

$$C = MA(CA_{EDt-1} + CA_{EX}) \qquad Eq. (4.19)$$

where MA is the maximum availability, CA_{EDt-1} is the previous endogenous capacity added and CA_{EX} is the exogenous capacity.

4.4.2.3.3. Reserve Margin

The reserve margin measures an electricity system's additional generating capacity to continuously meet peak demand, including periods of unplanned equipment outages and unexpected demand fluctuations (McPherson and Karney, 2014). The reserve margin is calculated by adding a state's electricity-generating capacity and dividing this by the peak demand in a year as shown in Figure 4.7.

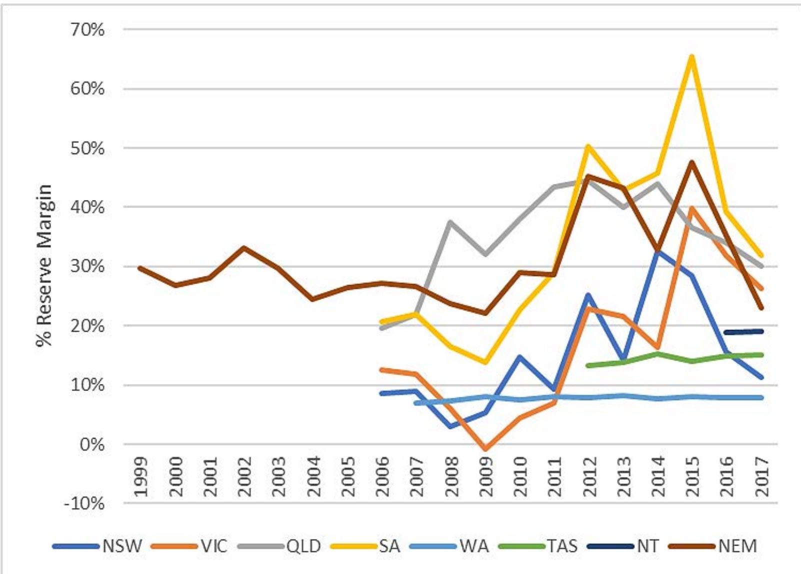

Figure 4. 7: Reserve Margin for Australian States and NEM.

This does not include embedded generation, off-grid generators and non-scheduled intermittent electricity supply, but includes the market-scheduled intermittent renewable electricity supply. The reserve margin in Australia's states and territory has declined in recent years due to heat waves and the retirement of coal power plants. The NEM was 45.2% in 2012, but declined to 23.1% by 2017. On the state level, New South Wales, Victoria, Queensland and South Australia experienced declines to 11.2%, 26.3%, 30% and 31.9%, respectively.

The removal of renewable energy technologies from the reserve margin will cause a decrease to approximately 15% in Victoria and South Australia, while New South Wales may rely on power imports from the NEM (Priftakis, 2017). Although Queensland power plants are primarily fossil fuel-powered, obstructing renewable energy sources in the NEM (e.g. low wind gains) may negatively impact the electricity supply's capacity. The LEAP model considers the reserve margin's changes from 2014 to 2017 and assumes the 2017 margin for the seven Australian states and territory; the reserve margin constraint is defined as follows (Ouedraogo, 2017):

$$\sum_{i=1}^{n} Cr_i \times GC_i \geq (1 + RM)PD \qquad Eq. (4.20)$$

where Cr_i is the capacity credit of the grid-connected power plant *i*, GC_i is the generating capacity of the grid-connected power plant *i*, RM is the reserve margin and PD is the peak demand from the grid system. The capacity credit is defined as a power plant's share of rated capacity. Typically, thermal and large hydropower plants have a capacity credit of 100%, while the capacity credit of grid-connected renewable energy technologies depends on their share in the total power generation capacity and availability. Table 4.4 presents the power plant characteristics used in this study.

Table 4. 4: Characteristic features of electricity generation technologies including cost assumptions (US$ 0.76 conversion rate).

Power plants/Fuel type	Capacity credit (%)	Capital cost (thousand US$/MW)		Fixed O&M cost (thousand US$/MW)		Variable O&M cost (US$/MW)	Fuel cost (US$/GJ)		Process efficiency (%)		Maximum availability (%)	Life time (Year)	Salvage value (thousand US$/MW)
		2014(A)	2050	2014(B)	2050		2014(B)	2050	2014	2050			
Coal steam/ bituminous, lignite	100	2.2	A*0.79	40.5 – 115.9	A*0.76	0.0008 – 0.0016	2.22	4.05	27 – 39.2	39.2	89.04	40	38 – 60.8
CCGT/ natural gas, oil	100	0.8	A*0.83	7.5-33.1	A*0.90	0.0053 – 0.0095	6.48	9.39	33 – 50	50	54.77	40	3.8 – 7.6
OCGT/natural gas, oil, CNG, CSM	100	0.5	A*0.90	10.7	A*0.85	0.0078 – 0.0079	6.48	9.30	29 - 34	34	53.29	30	3.8
Gas steam/natural gas, CSM	100	0.5	A*0.83	7.5	A*0.83	0.0053 – 0.0095	6.48	9.40	30 – 34	34	26.06	20	3.8
Large scale solar PV	36	1.8	A*0.60	22.5 – 22.8	A*0.26	0	-	-	100	100	25	25	15.2
Wind/onshore	36	1.9	A*0.77	32.7 – 33.8	A*0.76	0.0076 – 0.0113	-	-	100	100	25	20	7.6
Large scale hydro	100	2.4	A	42.5 – 44.6	B	0.0052 – 0.0053	-	-	100	100	35.6	50	11.4 – 76
Biomass/biomass, MSW, landfil gas	100	3.9	A*0.78	93.8	A*0.81	0.006 – 0.007	-	-	28	32.2	95	30	28.8
Battery strorage	100	3.4	A*0.29	22.5 – 22.8	A*0.26	0.0045 – 0.0046	-	-	100	100	95	10	3.8

Other/Landfil gas, natural gas, oil, CSM	100	0.5	A*0.78	7.5 – 33.1	A*0.81	0.0045 – 0.0053	-	-	40	22	95	30	7.6
Rooftop solar PV	100	1.8	A*0.60	1.5	A*0.26	0	-	-	100	100	25	25	2
Nuclear	100	4.2	A*0.90	26.1	A*0.90	0.0114	0.28	B*0.61	39.6	40	97.7	40	39
Supercritical coal PC with CCS	100	4.1	A*0.79	55.6	A*0.76	0.0068	2.22	4.05	31	37.9	89	50	38
CCGT with CCS	100	2.2	A*0.83	12.9	A*0.90	0.0091	6.48	9.39	44	50.5	50	40	7.6
Geothermal	100	3.1	A*0.73	152	A*0.62	0	-	-	100	100	95	30	60
Wave	26	4.5	A*0.56	30.4	A*0.55	0	-	-	100	100	98	20	7.6
Solar thermal	36	3.4	A*0.29	48.6	A*0.26	0.0038	-	-	100	100	25	25	19

Note: "A" indicates the costs in the column "2014" under "Capital cost (thousand US$/MW)". The "A" costs are multipled by the costs in 2050 column under "Capital cost (thousand US$/MW)" and the outcome are used in the analysis. "B" indicates the cost in column "2014" under "Fixed O&M cost (thousand US$/MW)". The "B" costs are multiplied by the costs in 2050 column under "Fixed O&M cost (thousand US$/MW)" and the outcome are used in the analysis. The "C" indicates costs in the column "2014" under "Fuel cost (US$/GJ)". The "C" costs are multiplied by the costs inn 2050 column under "Fuel cost (US$/GJ)" and the outcome are used in the analysis. Also note that "*" implies multiplication in each respective roles and column in the table.
Source: ACIL Allen Consulting (ACC, 2014) and Park et al. (Park et al., 2013)

4.4.2.3.4. GHG Emissions

The following calculation is conducted regarding the emissions from final energy consumption (Ouedraogo, 2017):

$$GHG = \sum_{i}\sum_{j}\sum_{f} Al_{f,j,i} \times EI_{f,j,i} \times EF_{f,j,i} \qquad Eq.(4.21)$$

where *GHG* denotes the emissions, *Al* is the activity level, *EI* is the energy intensity, *EF* is the emissions factor, *f* is the type of fuel consumed, *J* denotes the equipment, and *i* is the sector. The GHG in the transformation module is calculated as follows:

$$GHG_T = \sum_{s}\sum_{m}\sum_{t} ETP_{t,m} \times \frac{1}{f_{t,m,s}} \times EFG_{t,m,s} \qquad Eq.(4.22)$$

where GHG_T is the emissions resulting from the transformation module, *f* is the energy transformation efficiency, *EF* is the emission factor of one unit of primary fuel type *s* consumed in producing a secondary fuel type *t* through an equipment *m*.

4.4.2.3.5. Cost and Cost-Benefit Analysis

The total sector's cost is calculated as follows:

$$C_t = \sum_{i}\sum_{j}\left(\left[\sum_{f}\left(e_{f,j,k}ep_n\right) + \sum_{k}\left(m_{k,j}mp_k\right) + fc_{j,i}\right]p_{j,i}\right) \qquad Eq.(4.23)$$

where *C* is the C_t is the sector's total cost, ep_n is the unit price of fuel type *n*, $m_{k,j}$ is the demand for raw materials *k* per unit of production used in equipment *j* within the production process *i*, mp_k is the unit price of raw material *k*, and $fc_{j,i}$ is the fixed cost per unit of production through equipment *j*.

The LEAP model's cost-benefit analysis calculates the cost, represented as a positive sign +, and benefits, represented as a negative sign -, of one scenario as compared to another. This is typically a cost-benefit of the alternative scenarios compared to the base scenario. The entire energy system or part of the energy system can be covered when conducting a cost-benefit analysis within the LEAP model. This includes the capital and operating costs of installing and operating technology in the demand and transformation module; the cost of natural resource extraction and importing fuels; and the benefits of energy savings and optionally examining environmental externalities, if a cost is assigned to the pollutant (Emodi et al., 2017).

4.4.2.4. Decomposition Analysis of GHG Emissions

The LEAP model has been improved to conduct a decomposition analysis of the modelled GHG results; its decomposition analysis was developed using a Visual Basic script (.vbs), which exports relevant GHG results from the LEAP model to Microsoft Excel (the 2016 version or newer) and constructs a 'waterfall' chart[48]. This decomposes the change in the energy sector's GHG into its activity, energy intensity and emissions intensity effects. To use the Visual Basic script, this study edited the script code—specifically, lines 23 and 24, which are named 'mitigation' and 'reference'—to 'POL: POL_Low Carbon Economy_1' (or any alternative scenarios) and 'BAU: Business as Usual' for lines 23 (mitigation) and 24 (reference), respectively. The script was based on Ang's (Ang, 2005) study of the logarithmic mean Divisia index approach to the decomposition analysis.

4.4.2.5. Long Run Marginal Cost of Electricity

The marginal cost of electricity generation is the added cost of meeting an increase in demand over an extended period of time, or equally, the avoided cost by reducing generation by a specified amount (Tribunal, 2004). An analysis of marginal electricity generation costs can occur in the short- or long-term, or as a short run marginal cost (SRMC) or long run marginal cost (LRMC) (Kemp et al., 2011). The main difference is that the SRMC analyses the cost of the gradual change in demand by holding one production factor constant (e.g. capacity), while the LRMC analysis allows the production factors to occasionally vary. Therefore, the LRMC accounts for electricity companies' flexibility to expand their generation capacity to meet growing demand.

An analysis of the LRMC assumes the flexible expansion of generation capacity and long-term marginal operating costs, which include fuel costs, any applicable carbon tax, maintenance costs, and the capital costs spent on capacity expansion. Four methods are used to measure the LRMC: the perturbation; average incremental cost (AIC); total element, long-term incremental cost, and levelised unit-electricity cost approaches. The formal perturbation approach estimates how future costs will change due to changes in future demand; similarly, the AIC estimates demand variations' effect on future capital costs. The total element, long-term incremental cost approach assumes that no incumbent electricity production can supply the market and finds the least expensive combination of technologies to satisfy future demand. Finally, the levelised unit-electricity cost approach assesses the cost of meeting future demand (Administrator, 2012).

[48] https://www.energycommunity.org/default.asp

This study applied the AIC method due to its simplicity in assessing changing demand's effects on future costs; the approach is described as follows:

- Step 1: The LEAP model was used to forecast average the annual and maximum demand over the study period. This study used peak power requirements as the peak demand, which was available from the transformation result's output.
- Step 2: The least costly combination was developed using the LEAP's endogenous capacity expansion, which is based on the least costly capacity addition following merit order. This generates a future investment cost for capacity expansion based on an increase or decrease in electricity demand.
- Step 3: The present value of the optimal strategy's future cost, was divided by the present value of the additional demand supply. This was estimated using the AIC approach, as follows (Kemp et al., 2011):

$$LRMC = \frac{PV(NGC + MOC)}{PV(ADS)} \qquad Eq.(4.24)$$

where PV is the present value function NGC refers to the capital cost of the new generation investment required to meet future average and maximum demand; MOC is the marginal operating cost, or the additional costs of existing and new generation capacity required to meet future demand; and ADS is the additional demand served, or the demand beyond what is currently supplied with the existing generation capacity.

The PV calculates the present value of future amounts and is calculated as:

$$PV = [1 \div (1 + i)^n] \qquad Eq.(4.25)$$

Where *i* is the interest rate (which was taken as 7.5%) and *n* is the number of future years.

4.5. Results and Analysis

4.5.1. Technical Analysis

4.5.1.1. Energy Demand

Figure 4.8 presents Australia's energy demand outlook for the policy simulation. The results demonstrate that Australia's energy demand under non-climate conditions increases by 90% in the BAU case, 30% in the POL-LCE and 10% in the POL-LGRE, and declines by 30% in the POL-ARE scenario. Electricity, gas and water services account for approximately 32% of total energy consumption by 2050 under the BAU, while the transport and industry sectors account for 22% and 29%, respectively. Figure 4.9 presents the climate simulation's results and indicate that residential buildings tend to be the most energy-consuming compared to commercial service buildings under the RCP 4.5-BAU and RCP 8.5-BAU in Australia.

Figure 4. 8: Policy simulation for energy demand.

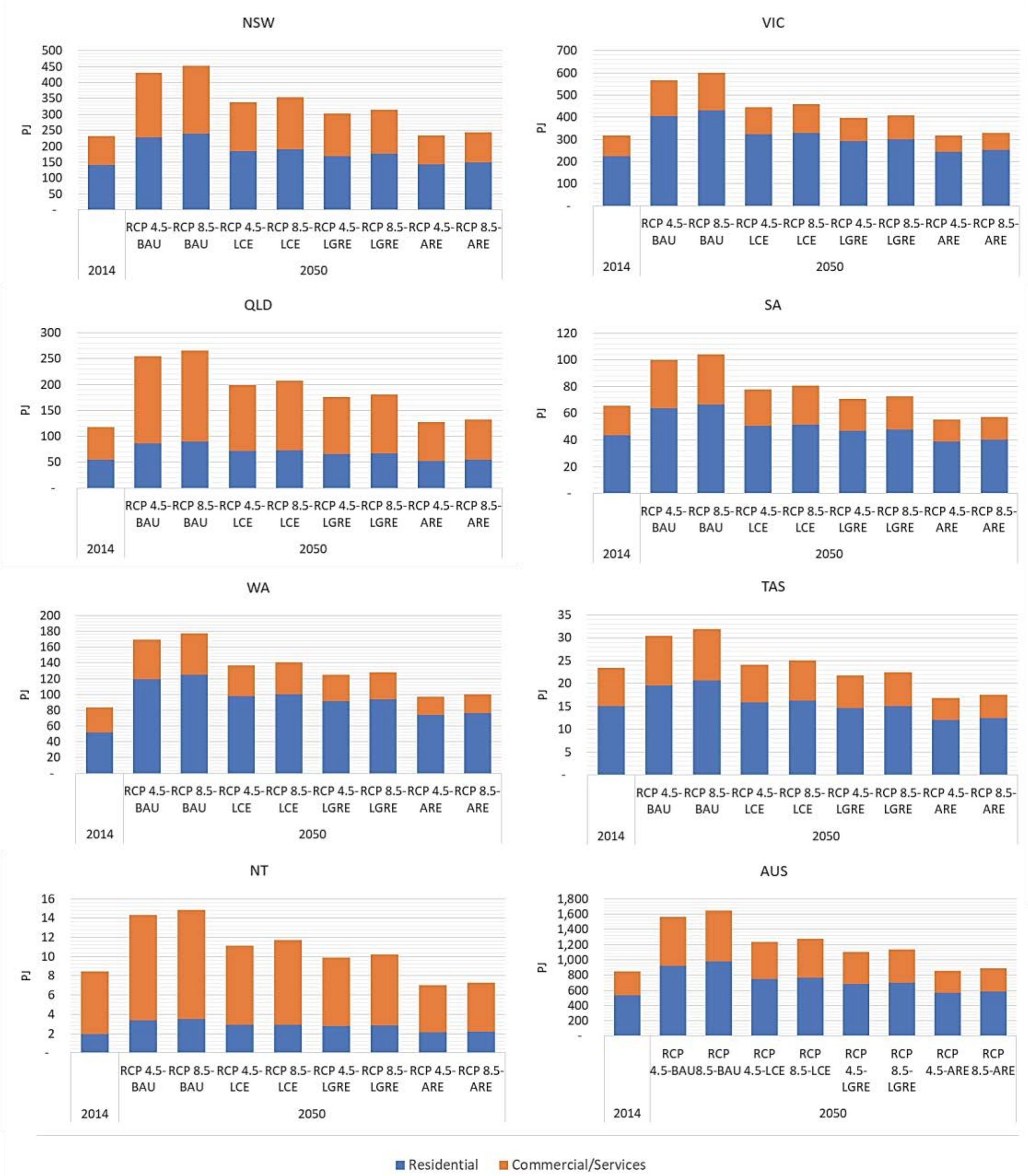

Figure 4. 9: Climate Change Simulation for Residential and Commercial Buildings.

Variations exist on the state level, as commercial services are observed to consume more energy for heating and cooling services in Queensland and the Northern Territory, with an almost equal share in New South Wales. When comparing policy and climate scenarios, energy consumption in the BAU will increase by 72 PJ in the RCP 4.5 and 150 PJ in the RCP 8.5. This increase will occur due to the increase in cooling demand during the summer months in New South Wales, Queensland and the Northern Territory. Further, winter peak demand is expected to increase Victoria's energy demand by 30 PJ and 62 PJ in the RCP 4.5-BAU and RCP 8.5-BAU, respectively.

4.5.1.2. Fuel Mix

The fuel mix as illustrated in Figure 4.10 reveals a shift towards electricity, biogas, natural gas and ethanol as Australia moves to the alternative energy resources.

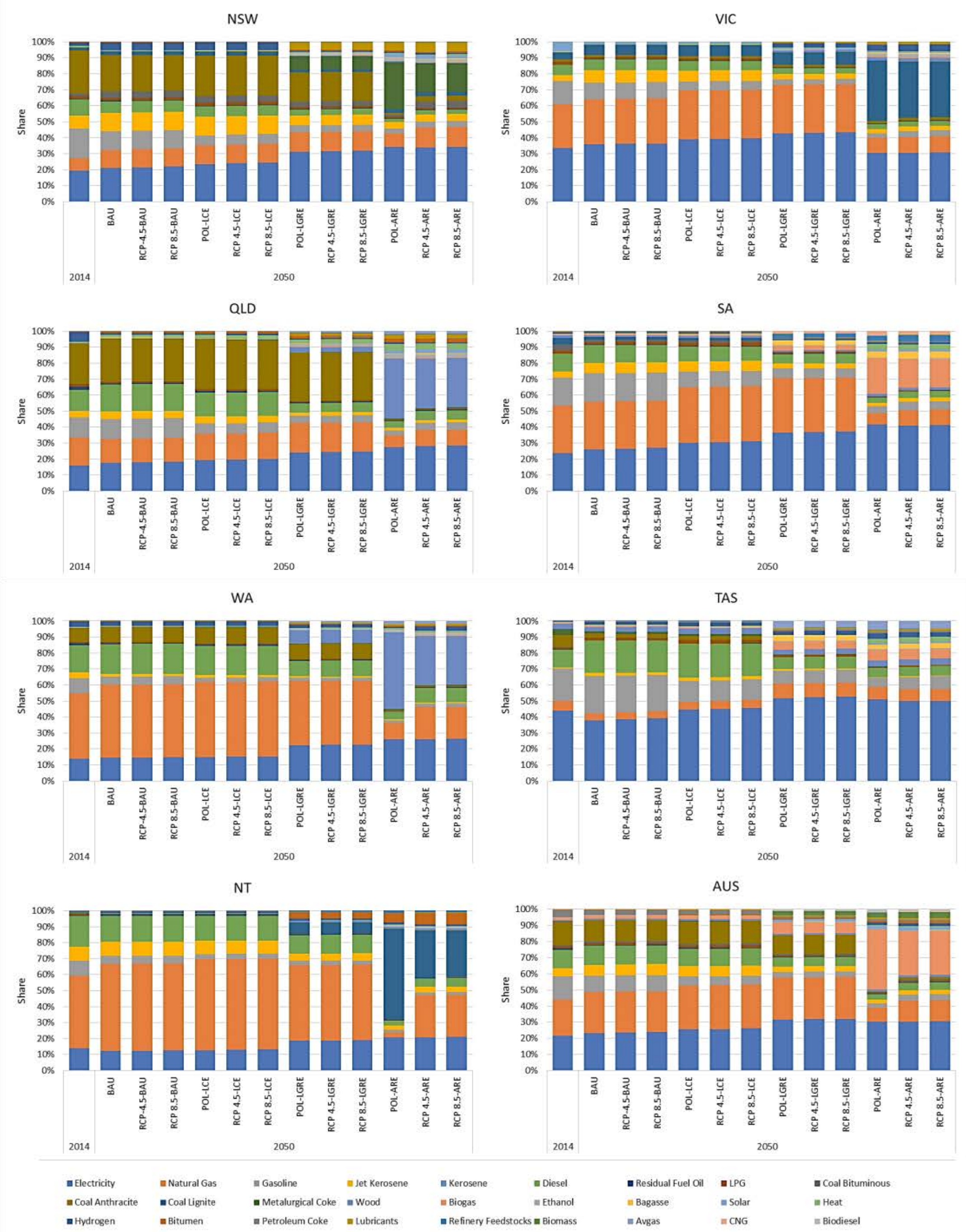

Figure 4. 10: Energy demand fuel mix under policy and climate change simulations.

The model results demonstrate that as the states explore the pathways towards a low carbon economy, away from the BAU scenario, diverse renewable energy technologies are not well-adopted across the states. This is due to the distribution of natural resources, decreasing energy intensity and substantial contribution of renewable electricity which varies across the states and territory. Fuel switching policies—including the electrifying of industrial processes and shifting to biogas use in the POL-LGRE and POL-ARE—will enhance the shift towards electricity use and make biofuel more attractive in the industry and transport sectors. The increase in the share of electricity also occurs due to the transport sector's electrification, as the model assumes that EVs and PHEVs are charged using grid electricity. The share of hydrogen for HFCVs were observed to be significant by 2050 in the transport sector by approximately 20%.

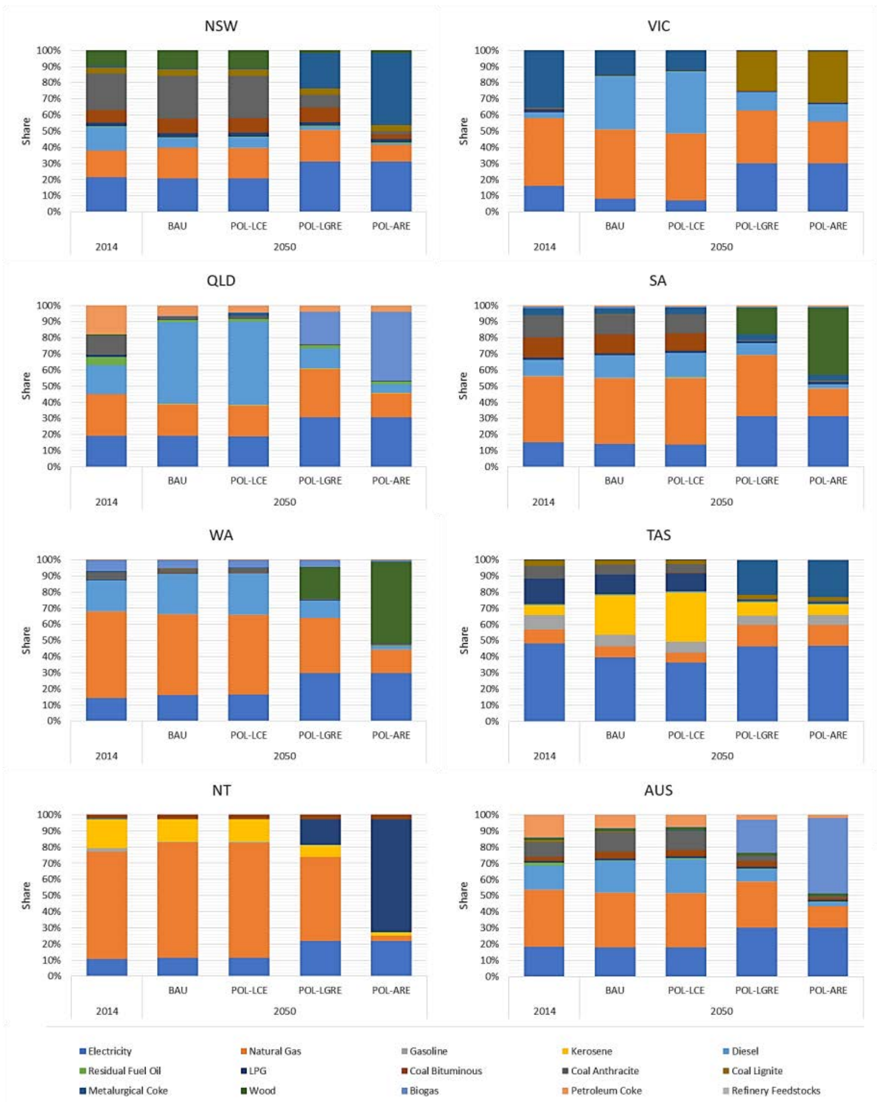

Figure 4. 11: Policy simulation for industry fuel mix.

Figure 4.11 provides a further look at the policy simulation for the industry sector, which demonstrates changes in fuel use for its industrial processes. The model results indicate that fuel-switching policy had the most effect in New South Wales, Queensland, South Australia, Western Australia and the Northern Territory, but only under POL-ARE. The fuel mix in POL-LCE scenario more closely resembled the BAU scenario due to an absence of fuel substitution policies. Therefore, fossil fuel resources, such as coal and diesel, will continue to play an important role in the mining and manufacturing sector until 2050 under the BAU and POL-LCE scenarios.

Road transport is a major energy-consuming subsector of the transport sector, at a 63% share in 2050, which is a decline of approximately 73% from 2014 under the BAU (Figure 4.12, top left panel). This is not due to an improvement in vehicle efficiency standards, but an increase in aviation travel, as Australia's tourism sector is expected to triple before 2050 (Australia, 2017c). Regarding the transport fuel mix, its electrification will begin to increase by 2021 (Figure 4.12, top right panel) due to an increase in the share of EVs and PHEVs in the road transport sector (Figure 4.12, bottom right panel). The transport sector's share of electricity reaches 23% and 29.2% in the POL-LGRE and POL-ARE, respectively, from 3.39% in the base year and 2.79% in the BAU by 2050.

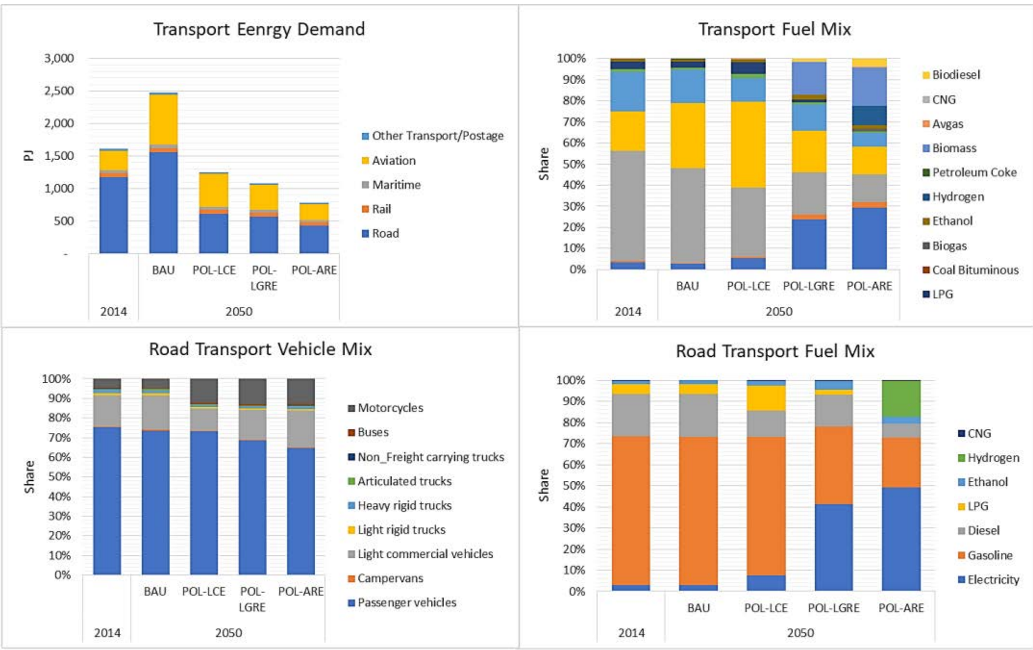

Figure 4. 12: Policy simulation for the transport vehicle and fuel mix.

Renewable fuels will also increase to 24.92% as biofuel becomes more attractive to airline operators, and as the share of ethanol E10 use increases for passenger cars. The increase in electric and biofuel in the road transport mix will lead to the reduction of gasoline and diesel use, to 36.7% and 15.1% in the LGRE scenario from the 65.6% and 12.3% share in the POL-LCE scenario. Electricity and hydrogen become the top three fuel sources in Australia in the POL-ARE scenario, further decreasing the share of gasoline, which is used in combination with ethanol to produce E10 fuel, to 23.5%.

4.5.1.3. Electricity Generation

Figure 4.13 illustrates the installed electricity generation capacity for the policy scenarios up to 2050; Table 4.4 displays the power plants' characteristics. It is observed in Figure 4.13 that Australia's installed capacity must expand to 104 GW under the BAU and specified reserve margin (as shown in Figure 4.7). The POL-LCE1 scenario will result in the closure of old coal and CCGT power plants by 2050, leaving gas-peaking plants. The introduction of supercritical coal pulverised coal with CCS, and CCGT with CCS, was endogenously added to reach approximately 9.4 GW and 17.3 GW, respectively, while old coal and CCGT power plants in the scenario are gradually withdrawn to maintain the system reserve margin until 2050. The expansion of renewable technology, such as large-scale solar, is constrained due to the CCS technology costs in the energy mix. This leads to the reduction of 1.9 GW of solar PV and 2.7 GW of wind capacity.

In the POL-LGRE, less investment in grid capacity's expansion is considered, and fossil fuel power plants are gradually retired and replaced with new, supercritical CCGT power plants, but with a combined capacity of 13 GW by 2050. The competition between the CCS costs and renewable energy technologies does not allow for the introduction of nuclear power plants in the LGRE, coupled with the latter's high installation costs. However, in the POL-ARE, old fossil fuel power plants are retired and replaced with large-scale solar PV of 26.6 GW and large-scale battery storage of 9.2 GW to dispatch power on demand.

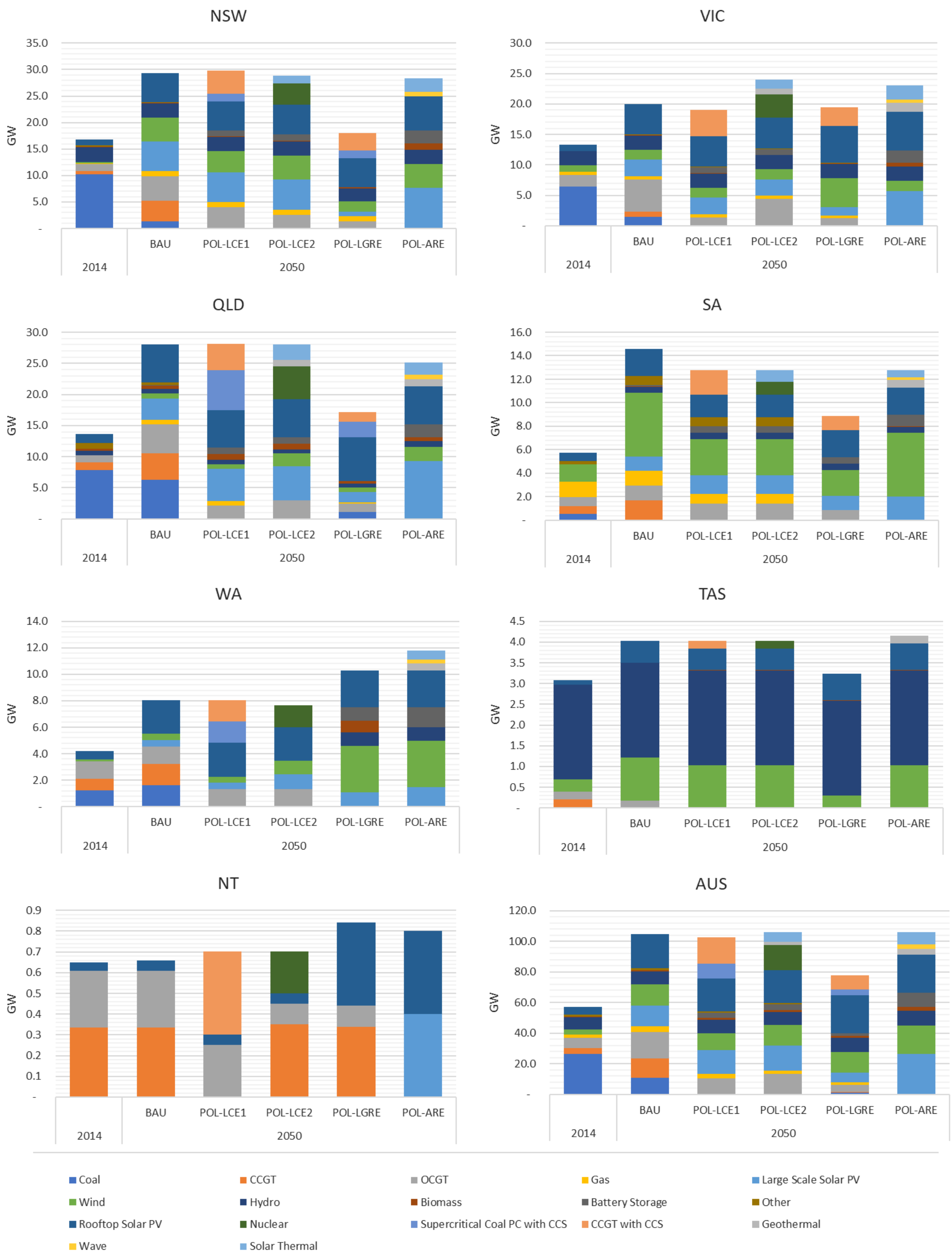

Figure 4. 13: Installed electricity generation capacity.

It is important to note that the generation capacity for the renewable-based POL-ARE scenario was higher than the BAU scenario. This can be attributed to the low-capacity credits of renewables in the higher power generation and installed capacity, which results in a lower power output than in the BAU scenario. This agrees with such studies as McPherson and Karney (2014), ClimateWorks (2014) and Awopone et al. (2017a). An examination of the policy and climate simulation displayed in Figure 4.14 implies increased temperature changes' effects on electricity supply.

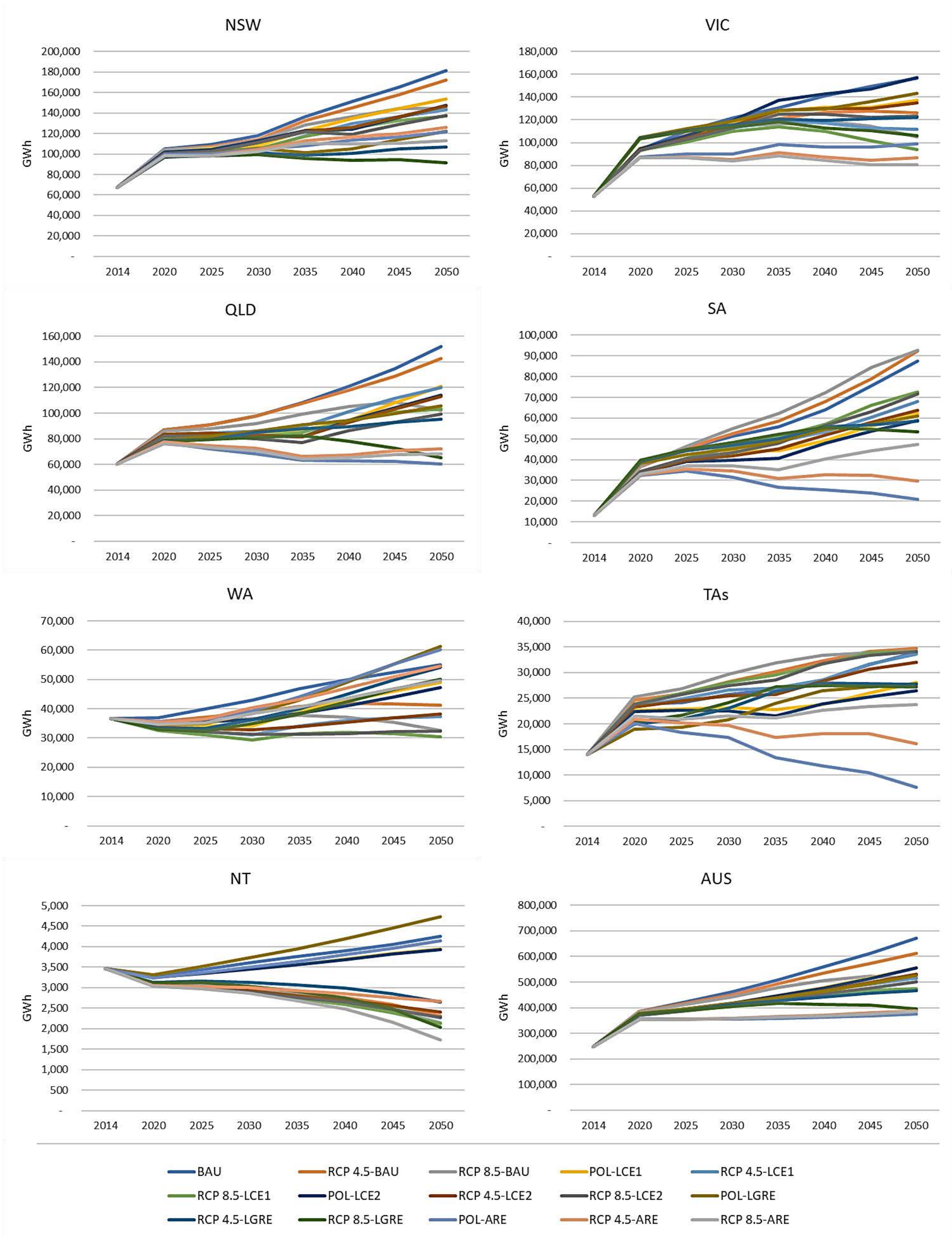

Figure 4. 14: Policy and climate change simulations for electricity generation.

In the POL-LGRE scenario, with low investment in grid generation technologies, severe climate change conditions (RCP 8.5) will affect power output in New South Wales by 30.9 TWh, Victoria by 37 TWh and Queensland by 40 TWh. From a national perspective, Australia's electricity generation will lose 59 TWh and 157 TWh of power output under the RCP 4.5-BAU and RCP 8.5-BAU scenarios. Fig. 8 also reveals that a low investment in generation capacity as stated in the LGRE may lead to a power deficit of 131.5 TWh under the severe climate change scenario. Electricity demand is projected to increase by 2050, by 730 TWh and 745 TWh in the RCP 4.5-BUA and RCP 8.5-BAU scenarios, respectively (see Figure 4.15).

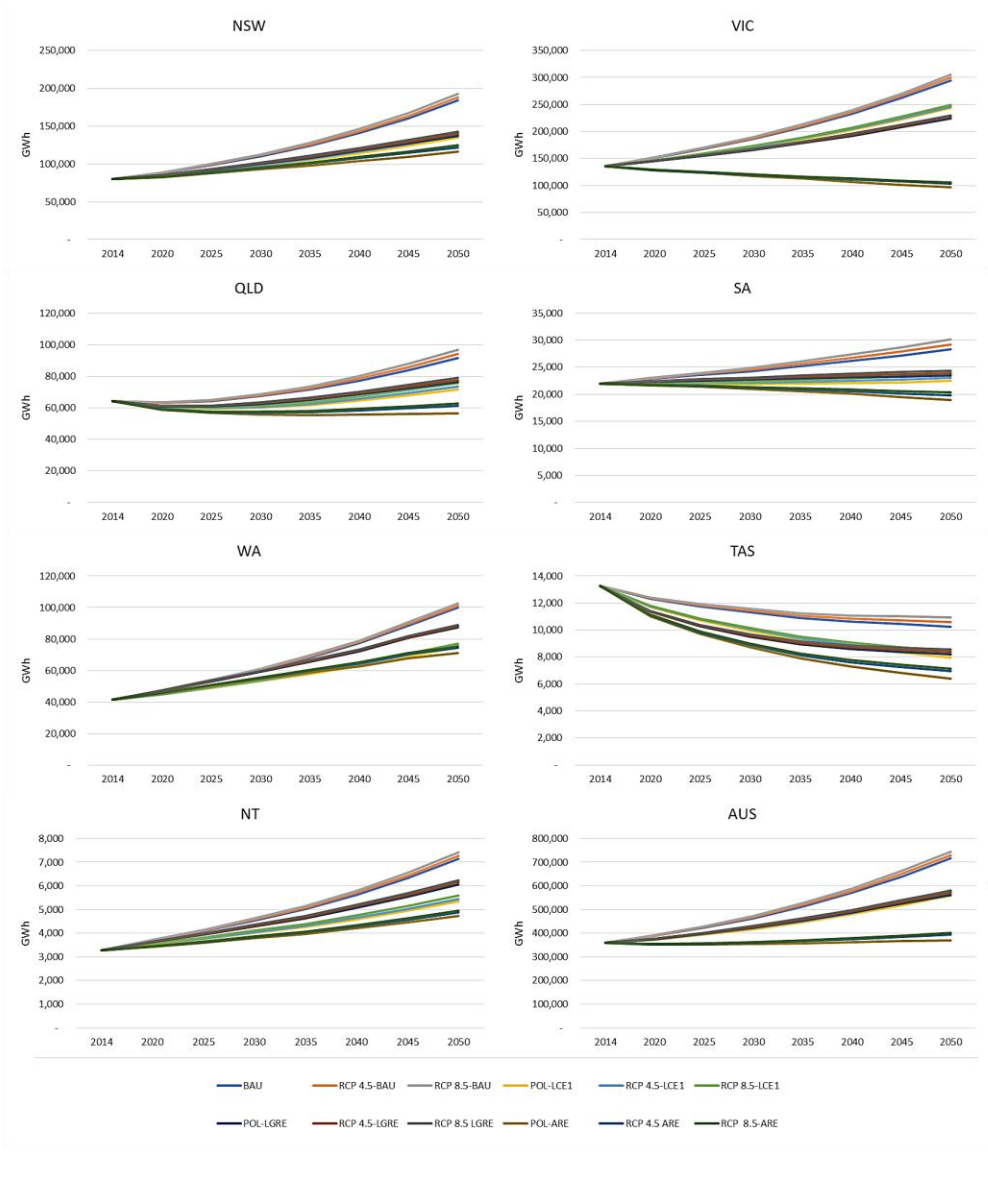

Figure 4. 15: Electricity demand under policy and climate change simulation.

Due to the low demand for grid electricity in the LGRE scenario, climate change conditions increase energy demand by 571.5 TWh and 579 TWh in the RCP 4.5 and 8.5 scenarios, respectively. In the RCP 4.5-ARE and RCP 8.5-ARE scenarios, electricity demand remains flat from 2014, with demand reaching 393.5 TWh and 400.8 TWh, respectively. Regarding the electricity-generation fuel mix, Figure 4.16 indicates that the share of coal in the BAU will decrease from 44% in 2014 to 10.4% by 2050.

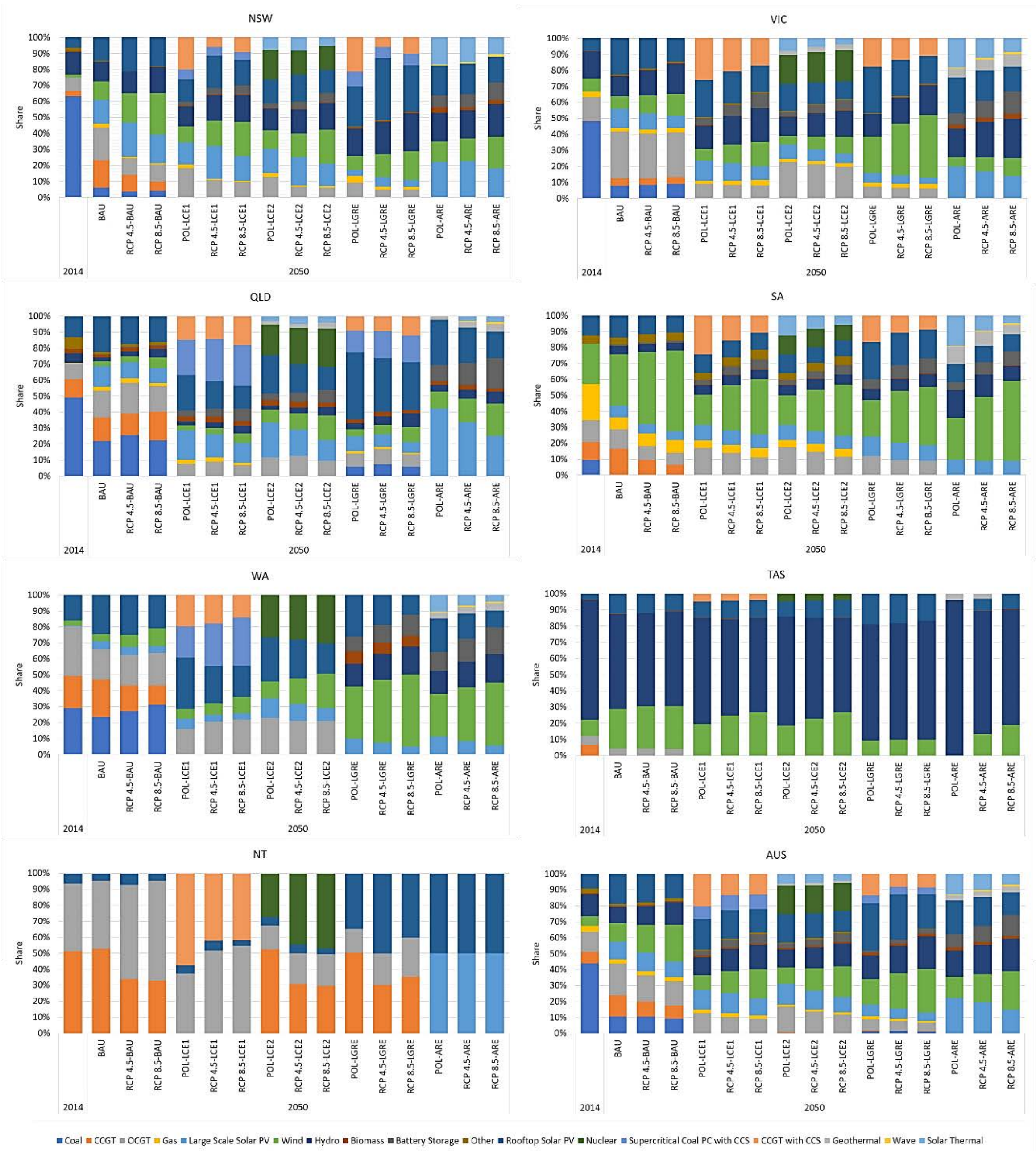

Figure 4. 16: Electricity generation technology mix.

Under the RCP 8.5 climate scenario, the share of coal decreases to 9.4% due to climate change, while gas power plants' electricity generation decreases by approximately 5%. The share of fossil fuel plants was observed to decline from the POL-LCE1 and POL-LCE2 to the POL-ARE scenario, as the installation of renewable energy technologies will increase in the POL-LGRE scenario and dominate electricity-generation technologies in the ARE scenario mix by 2050.

4.5.1.4. Fuel Switching

Figure 4.17 presents the fuel switching in Australia's electricity sector from 2014 to 2050. The results illustrate the effects of fuel substitution between the alternative scenarios and the BAU scenario. The POL-LCE1 scenario reveals that in 2020, an 8 TWh-power supply from solar energy will substitute 22 TWh of electricity generation in the BAU scenario alone. However, the solar energy trade-off in the BAU diminishes before 2040. Under climate change conditions, the solar output compared to the BAU decreases to 0.1 TWh by 2045, while bituminous coal comes online with 4.7 TWh due to a high demand for cooling and heating, and extends to 6.4 TWh by 2050.

Nuclear, solar and geothermal energies are the dominant fuel substitute for natural gas, coal and coal seam methane (CSM) in the LCE2 scenario from 2020 to 2050. The climate conditions in the POL-LCE2 scenario indicate that nuclear, solar and geothermal fuel substitutions to the BAU scenario substantially decrease. When comparing the LGRE and BAU scenarios, it is anticipated that wind power will become a fuel substitute from 2020 onward, while hydro and biomass energies will also become a viable substitute starting in 2025.

In the POL-ARE scenario, such renewable energy sources as waves, municipal solid waste (MSW), geothermal and a large share of solar completely replace the BAU fossil fuel-dominated fuel sources for electricity generation. Further, the POL-ARE renewables' fuel substitution capability were observed to withstand climate conditions, as the renewables' capacity will increase with back-up battery storage systems.

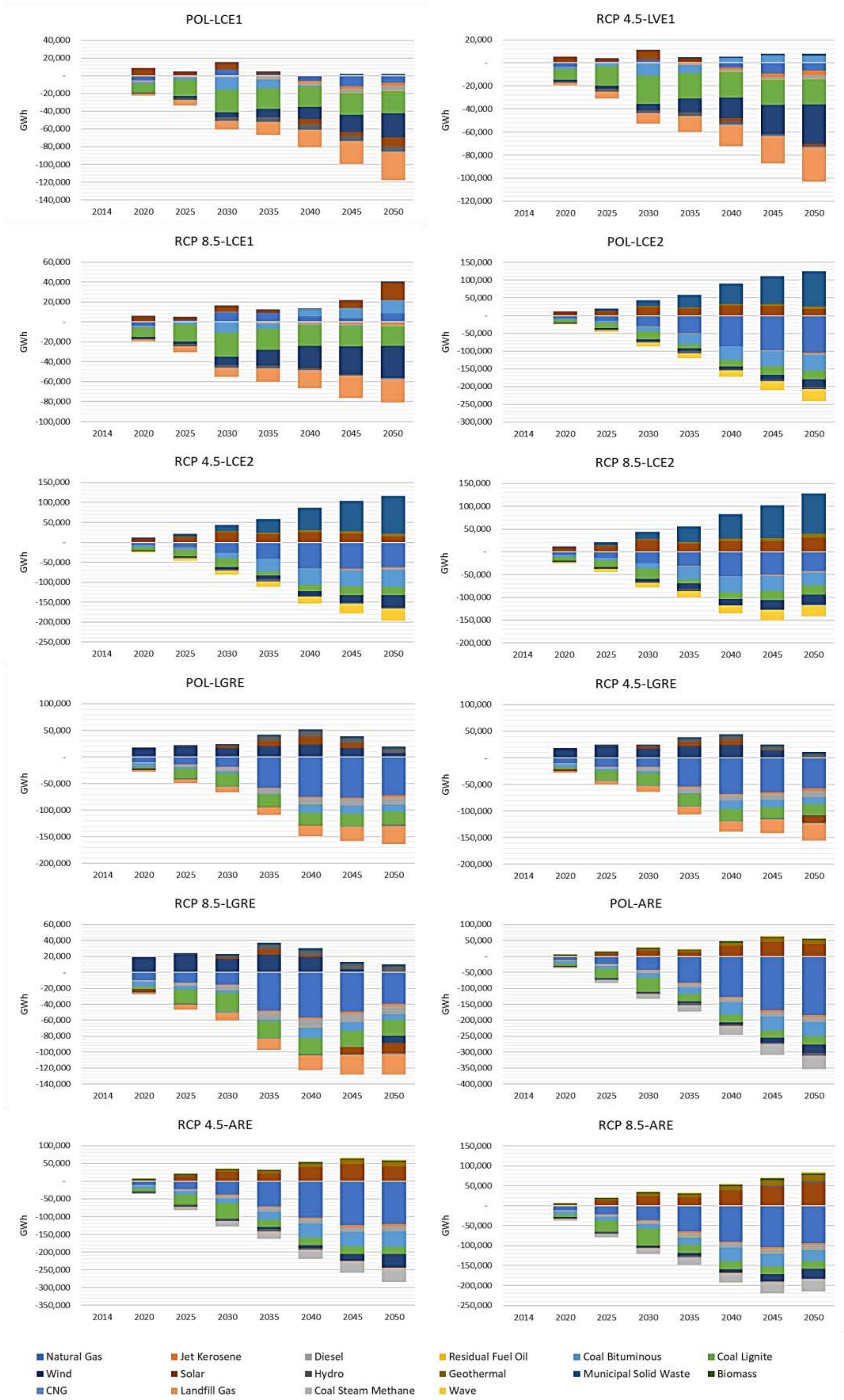

Figure 4. 17: Technology switching in the Australian Electricity Generation Sector.

4.5.1.5. Interregional Electricity Trade

An analysis on interregional electricity trading demonstrates that among the states participating in the NEM, Victoria is projected to arguably rely on net electricity imports to meet its future electricity demand across all scenarios (Figure 4.18).

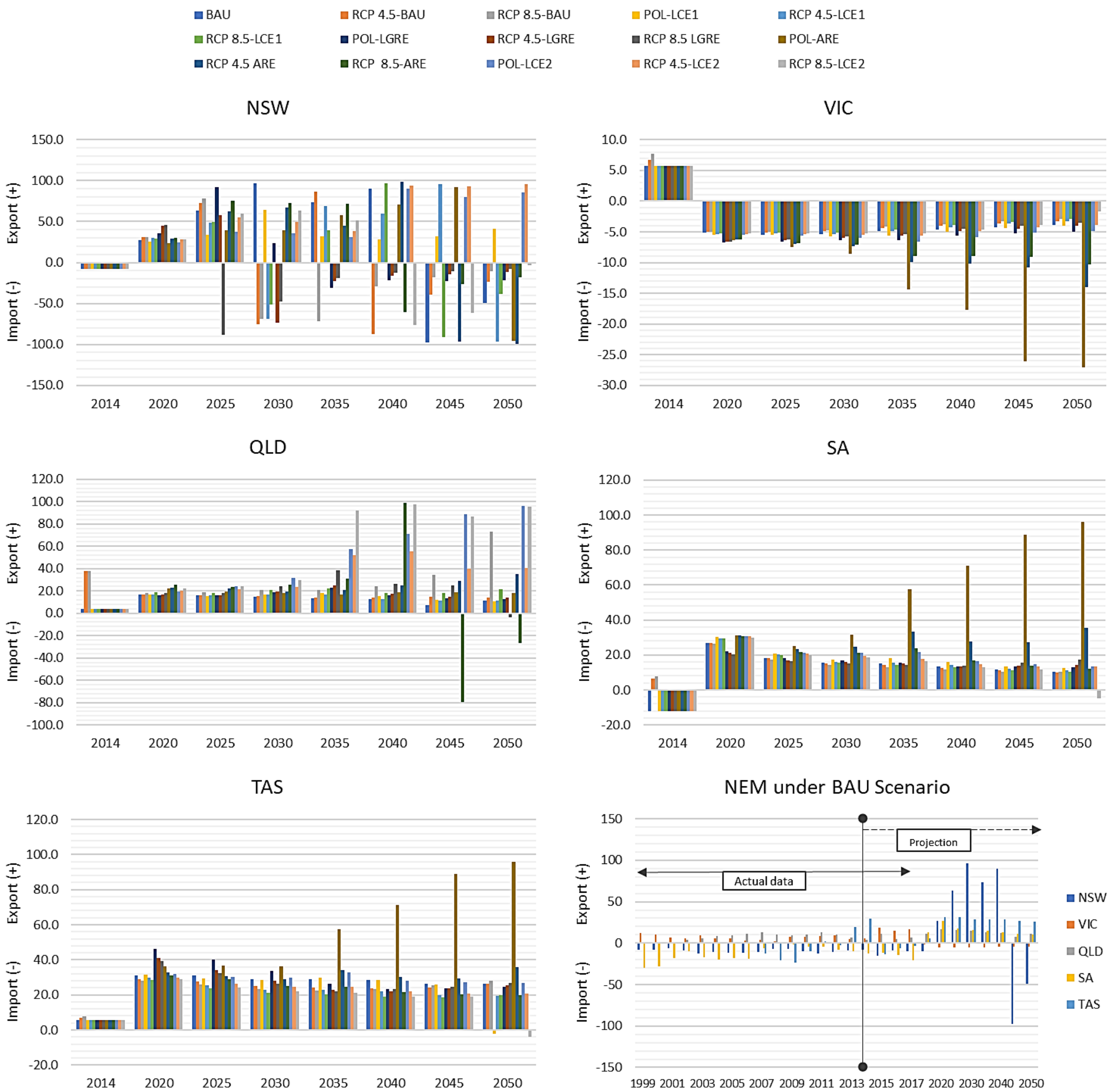

Figure 4. 18: Projected annual interregional electricity trade in the NEM (% of regional electricity demand).

This represents a shift in Victoria's average 5% import in 2014, which is expected to decrease to 4% by 2050, except in the POL-ARE scenario. Alternatively, Queensland, South Australia and Tasmania will become net exporters of electricity, except in the RCP

8.5-LGRE conditions for Queensland. The historical data on regional electricity trading—as noted in the bottom-right panel of Figure 4.18—indicates that South Australia's net imports decreased, from 29.8% in 1999 to 12% in 2014. The model's regional trade results note that by 2018, South Australia becomes a net exporter under the BAU scenario as investment grid electricity increases. A comparison of actual interregional trade data from (Regulator, 2018a) and projected data electricity trading reveals that differences of less than 1% occurred across the states between 2014 and 2018.

4.5.1.6. Changes in the Energy System's Structure

As Figure 4.19 illustrates, the Australian energy system is expected to transition from a base-year structure, in which commodity exports were approximately 20,167 PJ. However, as Australia expands its gas export capacity to become a global natural gas exporter (Jacobs, 2018) through LNG exports, natural gas production for exports is expected to increase, from 4,540 PJ in 2014 to 9,479 PJ by 2050 (Figure 4.20), as the share of other commodities decreases, such as coal. This will expand overall exports to 29,858 PJ and heighten local demands for electricity generation as well as demand-side consumption. Further, LNG exports reached 74 Mt (Paul, 2017) in 2017, and is forecast to increase by 22.6% in 2018 (Australia, 2017b).

This will invariably place pressure on gas prices, which may also affect Australia's rising electricity prices, among the most expensive worldwide. Electricity prices in some Australian cities—such as Sydney, Adelaide, Canberra and Melbourne—have increased from July 2017 by 15–20%, 16–20%, 19% and 23%, respectively (Martin, 2017). Prices also increased from 2015 due to the opening of three gas liquefaction plants at Gladstone, Queensland, which allowed for increased gas exports, originally intended to supply the domestic market. However, domestic gas consumption is projected to decline in the LGRE due to a low investment in fossil fuel power plants, and in the ARE scenario due to the retirement of gas power plants and a switch to biofuels.

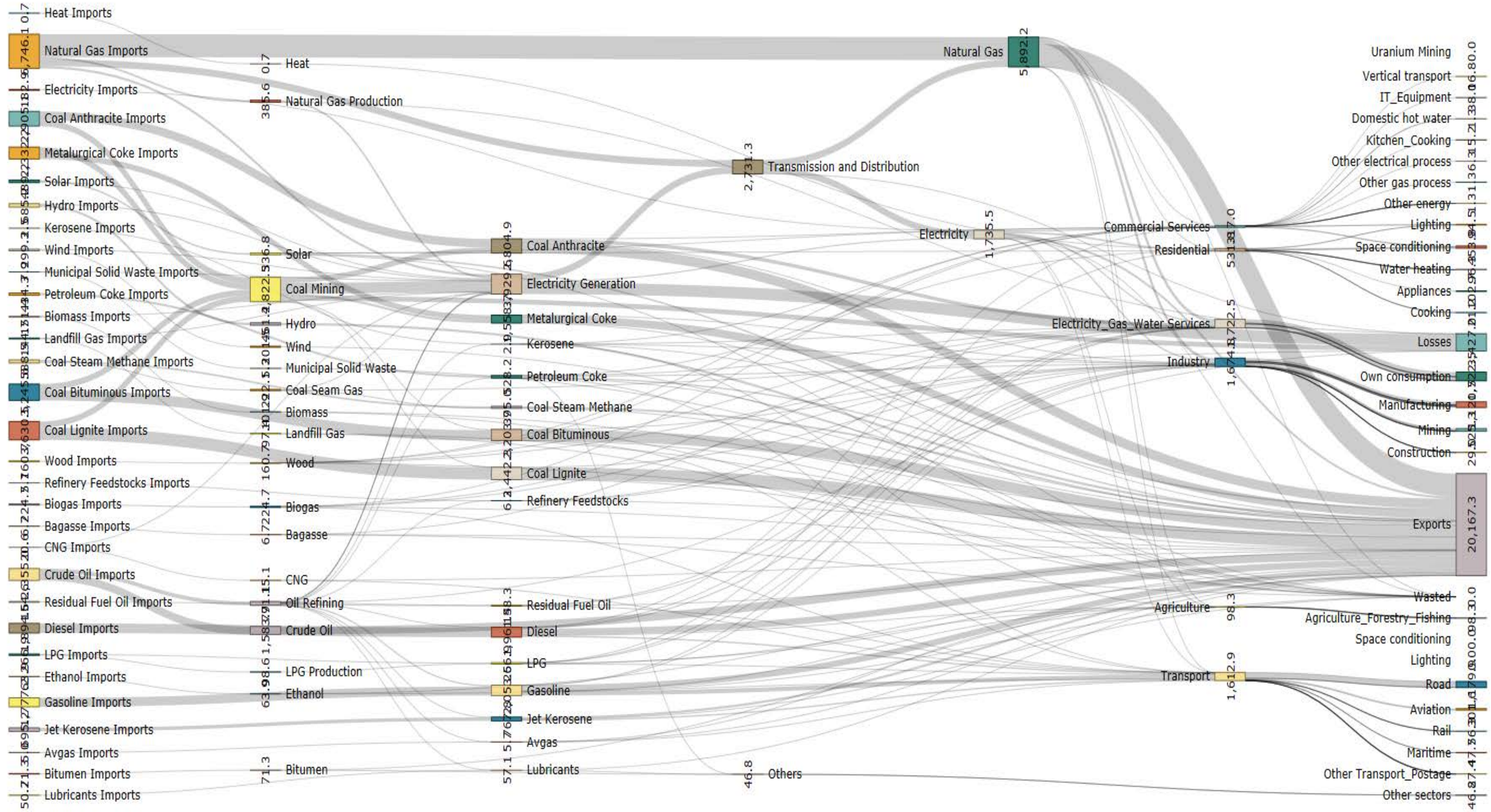

Figure 4. 19: Sankey Diagram for Australia Energy System in 2014.

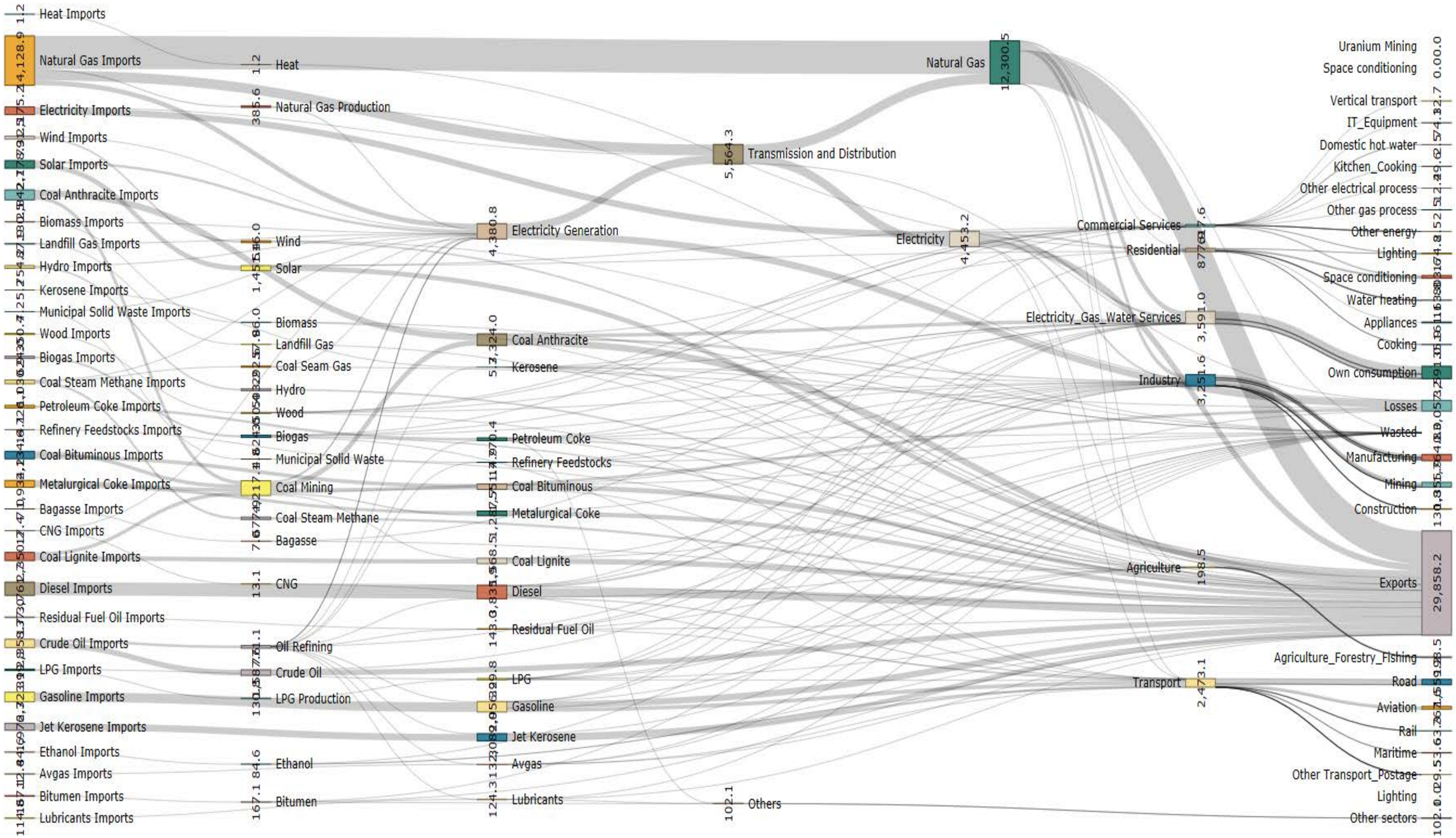

Figure 4. 20: Sankey Diagram for Australia Energy System by 2050.

4.5.2. Economic Analysis

4.5.2.1. Sales Revenue

The model calculated sales revenue under the policy and climate scenarios using residential electricity prices. Australia's retail electricity prices are based on standard and market plans; the former is regulated by the government, while electricity retailers design the latter. Market plans include discounts, competitive rates and other incentives to decrease electricity consumption costs. This study uses the market offer price due to a lack of available data on the choices in household electricity plans, and we assume that most households will choose a more affordable market offer over the standard offer. Retail electricity prices were retrieved from (AEMC, 2017), and are displayed in Table 4.5. Figure 4.21 presents the model's calculated sales revenue results.

Table 4. 5: Retail electricity price trends (US$ 0.76 conversion rate).

State/Territory	2016-17		2017-18		2018-19		2019-20	
	c/kWh	$/yr	c/kWh	$/yr	c/kWh	$/yr	c/kWh	$/yr
NSW	23.19	977	25.56	1,078	24.08	1,015	22.31	941
VIC	23.91	924	27.69	1,071	25.88	1,000	23.37	903
QLD	22.62	1,185	23.38	1,225	21.74	1,139	20.16	1,056
SA	27.01	1,351	30.35	1,579	29.43	1,471	27.15	1,357
WA	22.72	1,180	25.19	1,310	26.94	1,401	28.45	1,479
TAS	19.36	1,531	19.75	1,562	18.73	1,481	17.25	1,364
NT	21.52	1,423	21.64	1,430	22.17	1,466	22.73	1,503

Source: AEMC (Commission, 2017)

These results indicate that the sales revenue is expected to increase under the BAU scenario, from US$8.4 trillion in 2015 to approximately US$16 trillion in 2050. Under climate conditions, the sales revenues decrease to 8% and 21% in the RCP 4.5-BAU and RCP 8.5-BAU scenarios, respectively. Across the alternative scenarios, losses in sales revenue were higher in the POL-LGRE due to low investment in generation capacity. Further, electricity retailers may lose approximately 11% and 24% of their sales revenue under the RCP 4.5 and RCP 8.5 conditions.

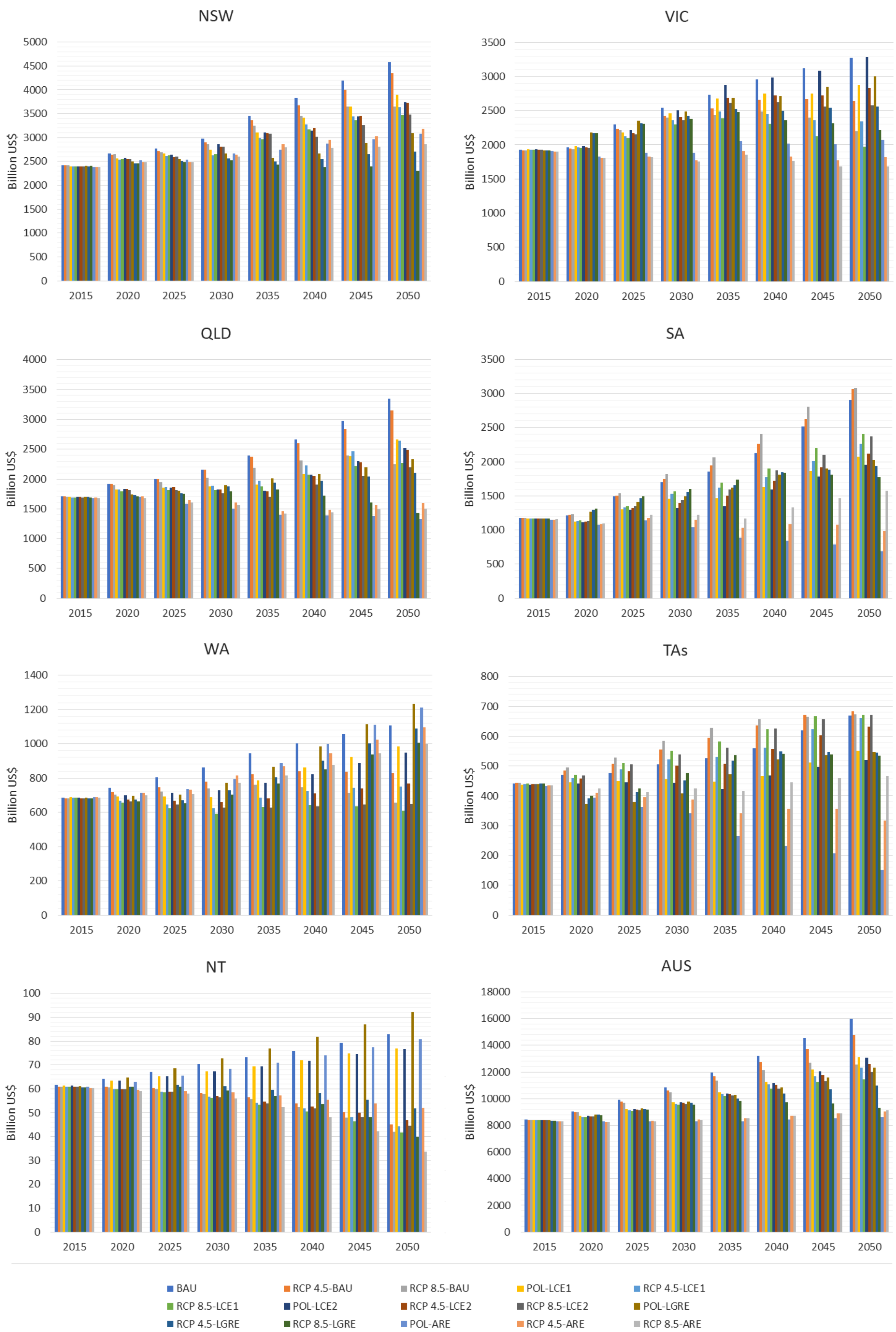

Figure 4. 21: Electricity sales revenue.

Between the CCS and nuclear pathways, losses were higher under the POL-LCE1 than with the POL-LCE2. A further observation notes that the 100% renewable electricity scenario experiences an increase in sales revenue despite climate conditions. The primary contributing factors may include not only the high installed capacity of renewable energy in the generation mix, but also the increased penetration of rooftop solar PV, which can boost revenue for both electricity retailers and prosumers.

4.5.2.2. Electricity Generation Costs

Figure 4.22 presents the costs associated with electricity generation in each scenario. The results demonstrate that the cost of generating electricity in the BAU will increase by 2050, from US$21.1 billion in 2014 to US$38.7 billion by 2050, or a 46% increase from the base year. Rising temperatures will affect generation output; consequently, the production costs in the RCP 4.5-BAU will increase by 9%, and further by 24% in the RCP 8.5-BAU scenario. A decline is observed by 2050 in the RCP 4.5-LGRE and RCP 8.5-LGRE scenarios by 14% and 29%, respectively. The decreased production costs are not due to efficiency improvements in the power sector, but the reduced electricity production under rising global temperatures. Meanwhile, electricity production costs were not affected in the RCP 4.5-LCE1, but by decrease of 3% in the RCP 8.5-LCE1 scenario. In the RCP 4.5-ARE and RCP 8.5-ARE scenarios, the cost of electricity production increased by 4% and 9% respectively compared to the non-climate POL-ARE scenario.

Across the alternative scenarios and compared to the BAU under non-climate conditions, the cost of electricity decreased by 47%, 41%, 73% and 88% in the POL-LCE1, POL-LCE2, POL-LGRE and POL-ARE scenarios, respectively. This implies that moving towards a low-investment, renewable option in the LGRE will result in a 73% savings in Australia's electricity generation costs, while a 100% renewable option (ARE) will lead to a significant cost savings of approximately 88% by 2050. The state-level results indicate that electricity generation cost savings will increase by 13%, 29%, 68%, 11% and 5% in New South Wales, Victoria, South Australia, Western Australia and Tasmania, respectively. On the other hand, costs under the BAU policy are projected to decrease in Queensland and the Northern Territory by 18% and 23%, respectively.

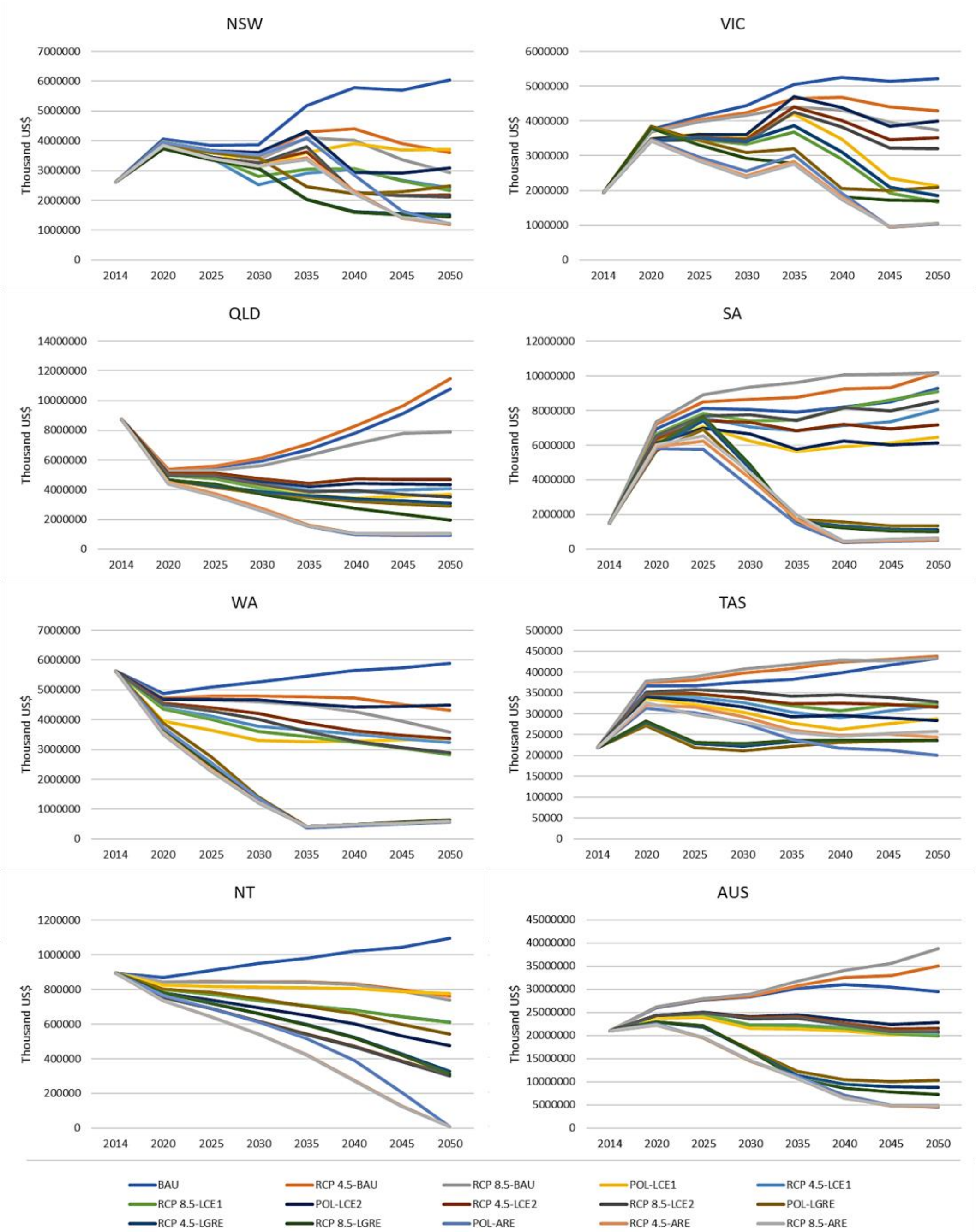

Figure 4. 22: Cost of electricity generation.

4.5.2.3. Long Run Marginal Electricity Costs

The marginal cost of electricity is the additional cost to generate a specified increase in output, or the cost avoided by reducing production by a specified amount. The marginal cost can be calculated for the short-term, in which one production factor is held constant, and long-term, with no constraints and reflecting the cost of the incremental change in demand (Kemp et al., 2011). The marginal cost indicates how much retailers must pay if they require additional units of electricity in the future. More importantly, if electricity prices are lower than the LRMC, then investment can be delayed and capacity retired. Alternatively, if wholesale electricity prices rise to more than the LRMC, then capacity expansion investments will be necessary to lower electricity prices towards the LRMC. However, an electricity market is expected to sustain a long-term situation in which prices are higher or lower than the LRMC of electricity (Administrator, 2012). Marginal cost base pricing ensures the most efficient utilisation of electricity (Malik and Al-Zubeidi, 2006), and we investigate the LRMC of electricity under policy and climate conditions over time.

This study's LRMC was calculated using the AIC method described in section 4.3.2.5 for an 18-year period (2014-2032 and 2033-2050). Table 4.6 presents the results for the five NEM states individually, and for the NEM, SWIS and I-NTEM; Table 4.7 displays the wholesale electricity price trends from 2016 to 2019 for comparison. The results reveal that the LRMC was lower than wholesale electricity prices by 2050 in New South Wales, Victoria, Queensland and Tasmania under the BAU scenario. Under climatic conditions in the BAU, prices in the LRMC tended to decrease by approximately 2 US¢/kWh in New South Wales and 1 US¢/kWh in Victoria. The LRMC in Queensland increased in the RCP 4.5-BAU and RCP 8.5-BAU by approximately 3 US¢/kWh and 2US¢/kWh, respectively.

The results reveal that the LRMC was lower than wholesale electricity prices by 2050 in New South Wales, Victoria, Queensland and Tasmania under the BAU scenario. Under climatic conditions in the BAU, prices in the LRMC tended to decrease by approximately US¢2/kWh in New South Wales and US¢1/kWh in Victoria. The LRMC in Queensland increased by 2050 due to an increase in the RCP 4.5-BAU and RCP 8.5-BAU by approximately US¢3/kWh and US¢2/kWh, respectively. In South Australia, Western Australia and the Northern Territory, the LRMC in 2032 and 2050 were higher than the wholesale electricity prices for 2016-2019 (see Table 4.7). Regarding the alternative scenarios, the LRMC in the POL-LCE1 was less than that in the POL-LCE2 scenario. However, the LRMC tended to maintain a US$1/kWh decline across the states considering RCP 4.5-POL-LCE2 and RCP 8.5-LCE2, while an increase in LRMC was observed in the RCP 8.5-LCE1 for South Australia, Western Australia and the Northern Territory.

Table 4. 6: LRMC of electricity (US¢/kWh).

	NSW		VIC		QLD		SA		TAS		NEM		WA (SWIS)		NT (I-NTEM)	
	2032	**2050**	**2032**	**2050**	**2032**	**2050**	**2032**	**2050**	**2032**	**2050**	**2032**	**2050**	**2032**	**2050**	**2032**	**2050**
BAU	8.52	8.36	9.34	8.35	15.16	17.76	37.53	26.53	3.63	3.18	13.61	13.01	30.08	26.73	65.46	64.49
RCP 4.5-BAU	7.61	5.26	9.36	8.52	15.89	20.11	39.60	27.54	3.47	3.15	13.94	13.21	30.36	26.29	71.51	82.13
RCP 8.5-BAU	7.56	5.11	9.27	8.91	15.45	19.31	40.99	27.44	3.37	3.16	14.16	13.17	30.71	27.56	72.36	86.38
POL-LCE1	6.98	6.06	7.83	3.87	11.61	7.65	33.93	26.00	3.20	2.57	11.11	8.13	22.82	17.26	58.09	49.28
RCP 4.5-LCE1	5.87	4.21	7.81	4.14	12.12	8.49	36.85	29.59	2.98	2.38	11.47	8.76	28.88	21.69	63.36	67.56
RCP 8.5-LCE1	6.39	4.27	7.80	4.44	11.55	7.49	38.11	31.36	2.89	2.37	11.72	9.38	29.24	23.32	64.16	71.44
POL-LCE2	8.27	5.24	7.76	6.38	13.27	9.56	39.07	26.00	3.45	2.69	12.12	8.87	31.32	23.77	48.51	30.33
RCP 4.5-LCE2	7.41	3.70	7.78	6.50	13.81	10.39	41.19	28.18	3.24	2.47	12.42	9.10	30.68	22.08	50.95	32.39
RCP 8.5-LCE2	7.40	3.87	7.74	6.51	13.02	8.90	42.09	29.81	3.12	2.41	12.47	9.52	30.78	22.35	51.49	33.30
POL-LGRE	8.16	5.11	7.07	3.66	10.33	6.94	18.42	5.59	2.51	2.12	9.18	4.96	6.26	2.59	47.79	28.61
RCP 4.5-LGRE	7.50	3.55	6.96	3.83	10.86	8.15	18.74	4.89	2.36	2.14	9.14	4.80	6.04	2.87	51.64	30.82
RCP 8.5-LGRE	7.50	3.96	6.88	4.03	10.73	7.56	18.80	4.83	2.30	2.18	9.12	4.66	6.04	3.13	53.27	38.40
POL-ARE	8.71	2.51	7.26	2.65	8.07	3.92	22.89	5.87	4.13	6.56	9.22	3.16	5.88	2.39	40.68	0.59
RCP 4.5-ARE	7.62	2.40	7.40	3.04	8.12	3.60	23.82	4.58	3.71	3.78	9.13	3.09	5.53	2.69	41.99	0.91
RCP 8.5-ARE	7.74	2.74	7.32	3.32	7.82	3.97	24.06	3.40	3.16	2.72	9.19	3.22	5.68	2.99	44.54	1.41

Table 4. 7: Wholesale electricity price trends (Price in US$ at 0.76 conversion rate).

State/Territory	**2016-17**		**2017-18**		**2018-19**		**2019-20**	
	US¢/kWh	**$/yr**	**US¢/kWh**	**$/yr**	**US¢/kWh**	**$/yr**	**US¢/kWh**	**$/yr**
NSW	7.27	306.28	9.45	398.24	7.80	329.08	5.98	252.32
VIC	7.44	288.04	11.03	426.36	8.98	347.32	6.34	244.72
QLD	7.37	386.08	8.98	470.44	7.56	395.96	6.16	323.00
SA	9.96	497.80	13.53	676.40	11.35	567.72	8.03	402.04
WA	9.26	481.08	10.07	523.64	10.62	551.76	11.00	571.52
TAS	4.95	391.40	6.75	533.52	5.36	424.08	3.72	294.12
NT	11.16	737.96	11.16	737.96	11.45	756.96	11.73	775.96

Note: does not include regulated network cost (tranmission and distribution cost) and envrionmental policies (e.g. solar bonus scheme, large abd small renewable energy schemes). Source: AEMC (Commission, 2017).

In the POL-ARE and POL-LGRE, the LRMC declined to 2.12–28.61 US¢/kWh across the states and market. Therefore, low grid investments and 100% renewable technologies can potentially decrease wholesale electricity prices, which will also decrease final consumers' retail electricity prices. The retirement of coal power has been an important factor leading to Australia's recent increase in electricity prices. For example, the closure of the Hazelwood power plant increased wholesale electricity prices in Victoria (Harrison, 2018). Further, an increase in gas prices impacts electricity prices, which will be passed to the final consumer (Fraser, 2017). Our results indicate that global warming in the RCP 8.5-BAU scenario may lead to an overall increase in LRMC by 2050 in Victoria, Queensland, South Australia, as well as in the NEM and I-NTEM. Across the states, electricity market and scenarios, the results demonstrate that an investment in the POL-ARE scenario will significantly reduce the LRMC of electricity in such states as New South Wales, Victoria, and Queensland, as well as across the three electricity markets (NEM, SWIS and I-NTEM). Meanwhile, lower grid investment favours a reduction in LRMC in South Australia and Tasmania more than in the POL-ARE scenario.

4.5.2.4. Cost-Benefit Analysis

Table 4.8 presents the economic results, in terms of the alternative scenarios' cumulative costs and benefits relative to the BAU, for the 5% and 10% discount rates. The cost-benefit analysis describes the best possible approach in a policy's adoption, and reveals that investment in demand-side policies will even out in the POL-LCE1 scenario. However, an added cost of approximately US$708,000 was observed due to the installation costs for CCS technologies in the industry sector. Energy efficiency policies under the POL-LGRE scenario will yield a cumulative benefit of US$1.9 billion by 2050. Similarly, the cumulative benefits for commercial services increase to US$32.5 billion, and the cumulative benefits double in the residential and commercial services sector in the POL-ARE scenario. It is also noteworthy that the benefit gaps in the transport between the POL-LGRE and POL-ARE were US$603 million and US$102 billion, respectively. These benefit gaps occurred due to the high penetration rate of EVs, PHEVs and HFCVs; a mode shift to public bus services that decrease passenger vehicle use; a decrease in aviation travel, as 15% of passengers move to rail services; and an overall improvement in both passenger vehicles and the aviation industry.

Table 4. 8: Cumulative costs and benefits for the period 2014-2050 for Alternative scenarios relative to the BAU scenario at 5% and 10% discount rate.

Million US$	5%				10%			
	POL-LCE1	POL-LCE2	POL-LGRE	POL-ARE	POL-LCE1	POL-LCE2	POL-LGRE	POL-ARE
Demand	0.7	-	-3,934,034.3	-4,941,555.1	0.5	-	-1,497,946.9	-1,885,548.7
Residential	-	-	-1,852.5	-3,900.9	-	-	-735.9	-1,531.2
Commercial Services	-	-	-32,540.6	-517,480.7	-	-	-12,541.4	-202,852.3
Industry	0.7	-	-630,832.8	-630,832.8	0.5	-	-232,145.4	-232,145.4
Agriculture	-	-	-3,268,205.2	-3,268,205.2	-	-	-1,252,344.2	-1,252,344.2
Others	-	-	-	-	-	-	-	-
Electricity/Gas/Water	-	-	-	-418,304.8	-	-	-	-154,335.1
Transport	-	-	-603.2	-102,830.6	-	-	-180.0	-42,340.5
Transformation	-1,514.5	287.6	-4,721.8	-4,848.6	-919.6	-119.9	-1,450.8	-1,814.7
Resources	-3,543,267.1	-3,700,613.1	-664,316.2	-6,074,615.6	-1,290,485.0	-1,425,495.7	-354,218.5	-2,364,512.4
Imports	-34,170,520.0	-37,657,167.9	-13,310,430.7	-66,989,467.4	-14,072,689.8	-15,680,734.8	-9,527,216.0	-28,642,302.5
Exports	30,627,252.9	33,956,554.8	12,646,114.5	60,914,851.8	12,782,204.8	14,255,239.1	9,172,997.5	26,277,790.1
Environmental Externalities	-26,115.1	-24,153.2	-34,424.5	-47,024.1	-10,623.4	-9,705.6	-13,646.3	-19,220.8
Net Present Value	-3,570,896.0	-3,724,478.7	-4,637,496.9	-6,126,488.2	-1,302,027.6	-1,435,321.2	-1,128,631.3	-4,345,274.4

Note: minus (-) sign represent benefit and plus (+) sign represent added cost to the economy.

The transformation sector reached US$1.5 billion in the POL-LCE1. Alternatively, nuclear power plants' expansion in the POL-LCE2 will lead to an added cost of US$287.9 million. The POL-LGRE's transformation branch reveals the benefits of low-grid electricity investment (US$4.7 billion) comparable to the benefits in the high-renewable investment POL-ARE scenario (US$4.8 billion). This is due to the low fuel and investment costs of fossil fuels and RET in the POL-LGRE, thereby allowing improved energy efficiency and solar PV installation. The increased benefits in the POL-ARE scenario are due to the projected decline in the cost of RET, no fuel costs and increased energy efficiency practices and RET. Lower discount rates favoured the expansion of renewable energy technologies, followed by CCS technologies, but not nuclear power plants. Further, high discount rates will encourage investment in nuclear power plants, which require higher upfront capital costs compared to other low-carbon technologies. This is also the case when higher discount rates affect energy efficiency practices, such as insulation and switching to high-efficiency appliances.

Regarding resource imports and exports, Table 4.8 demonstrates that international resource trading leads to a benefit of US$6.07 trillion in the POL-ARE scenario due to the low domestic requirements for fossil fuel imports. Resource trading in the POL-LCE1 and PLO-LCE2 scenarios resulted in US$3.5 trillion and US$3.7 trillion in benefits. The results indicate environmental[49] benefits of US$34.4 billion and US$47 billion in the POL-LGRE and POL-ARE scenarios, respectively. When a 10% discount rate is considered, the benefits decrease to US$13.7 billion and US$19.2 billion, respectively; this implies that decreasing the discount rate will enable the government to reduce the environmental damages associated with fossil fuel utilisation, but higher discount rates decrease the environmental benefits. The POL-ARE costs' net present value was significantly lower than the BAU, LCE1 and LCE2. This is primarily due to the significant savings in fuel costs and low investment costs of future renewable technologies, which will be competitive with fossil fuels. At a higher discount rate, the POL-ARE scenario is still competitive with other low-carbon scenarios.

[49] The environmental externality cost was retrieved from EVANS, C., NAUDE, C., TEH, J., MAKWASHA, T. & AI, U. 2014. Updating Environmental Externalities Unit Values. *Austroads*. A reviewer pointed out that the externality cost was outdated, and the values had an influence on the results. We explained that updated externality values were not available when the research was conducted. However, we acknowledge this shortcoming and urge readers to be aware that the externality cost was from 2014, which is the study's base year and only values available for Australia in 2018 (to the best of the authors' knowledge).

4.5.2.5. Sensitivity Analysis

Four types of plant-level costs were identified in Samadi (2017): capital costs; fuel costs; the market costs of GHG emissions; and non-fuel operations and maintenance costs, both fixed and variable. Among plant-level costs, energy technologies' capital costs are projected to decline before 2050, as noted in Table 4.4, while fossil fuel costs have been highly volatile over the years. Therefore, it is important to investigate the sensitivities of energy investment and fuel costs to determine the scenarios' performance under various economic conditions. This study's sensitivity analysis varied investments' and fuel costs' values by ±20%; Figure 4.23 presents the results, in which the upper section displays the net present value, and the lower section notes the percentage changes of the alternative scenarios compared to the BAU scenarios.

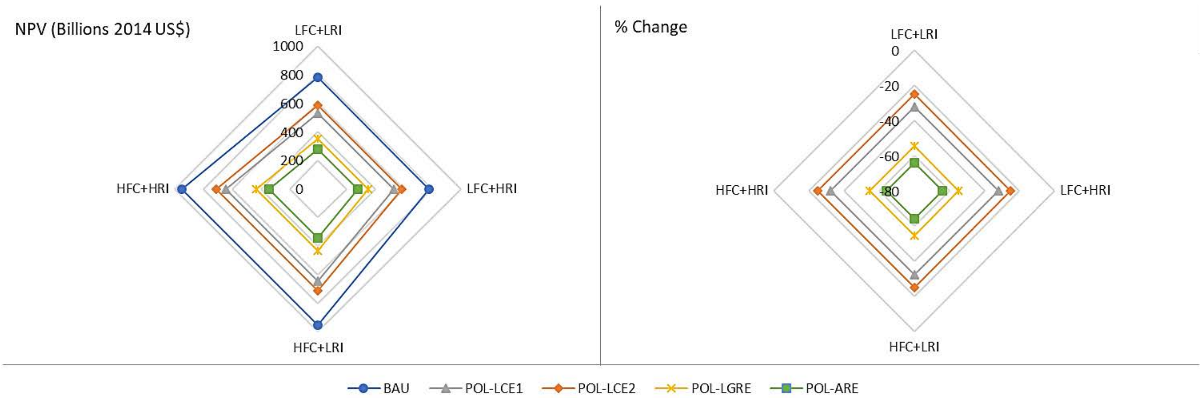

Figure 4. 23: Sensitivity analysis of scenario performance under changes in fuel cost and renewable energy investment.

The results of the net present value in Table 4.8 indicate a similar trend as observed in Figure 4.23, in which the POL-LGRE and POL-ARE were less expensive than the BAU, POL-LCE1 and POL-LCE2 scenarios. A closer observation reveals that the POL-ARE scenario was more resilient to changes in fossil fuel prices and investment costs for renewable energy technologies. The percentage change reveals that economic conditions affect the POL-LCE2, which is the nuclear scenario, followed by the POL-LCE1, which is the CCS scenario. However, the POL-LGRE and POL-ARE scenarios were 54.66% to 64.10% less expensive than the BAU scenario.

4.5.3. Environmental Analysis

4.5.3.1. GHG Emissions

The emissions factor used in this study was derived from the Intergovernmental Panel on Climate Change's Fifth Assessment Report with climate feedback (IPCC, 2018a). Figure 4.24 illustrates the cumulative GHG emissions for the policy and climate change simulations compared to the BAU. Higher emissions of 40 and 73 million metric tons of carbon dioxide equivalent ($MtCO_2eq$) were observed by 2050 in the RCP 4.5-BAU and RCP 8.5-BAU, respectively, compared to the non-climatic BAU scenario. This implies that if future climate conditions exceed +2^{0}C under the BAU scenario, GHG emissions may further increase between 40–73 million $MtCO_2eq$. The introduction of CCS in industries, fuel efficiency standards in the transport sector and CCS technology for new super-critical coal and CCGT power plants (POL-LCE1) can save approximately 5.5 billion $MtCO_2eq$ of GHGs by 2050.

The nuclear option (POL-LCE2), with CCS technology implementation in the industry sector, exhibited less potential to reduce GHG emissions (2.4 billion $MtCO_2eq$) than the POL-LCE1 scenario. The POL-ARE scenario had the largest decrease in GHG emissions, or approximately 13 billion $MtCO_2eq$ lower than in the BAU scenario. Further, the POL-LGRE has a higher potential to reduce emissions under climate change conditions, followed by the POL-LCE2. The results also indicate that New South Wales, Victoria, Queensland, and Western Australia have a high potential for emissions savings by 2050, which range from 2.6 to 3.5 billion $MtCO_2eq$ in the renewables-dominated POL-ARE scenario. This confirms renewable technologies' contribution to reducing GHG and meeting emissions reduction targets. In fact, Australia can save on the costs of electricity generation and its capacity expansion by investing in 100% renewable technologies. This will transform the country from one of the most coal-dependent countries worldwide (Sawe, 2017), with the highest CO_2 emissions per capita (Bank, 2018), to a green economy by 2050.

It is important to note that the increased switching to biofuels may have two negative effects on the environment and society. First, the potential exists to increase competition for land resources to grow food, and for other agricultural purposes. Further, an unsustainable land utilisation for biofuel crops can result in deforestation, which combined with climate change may lead to desertification if unchecked. The second effect involves the potential increase in GHG emissions, as resources might be renewable, but their consumption emits more carbon per energy than other fossil fuels (PFPI, 2018). Future studies should examine the implications of excessive biomass use for fuel production on agricultural land and the environmental effects in an Australian context.

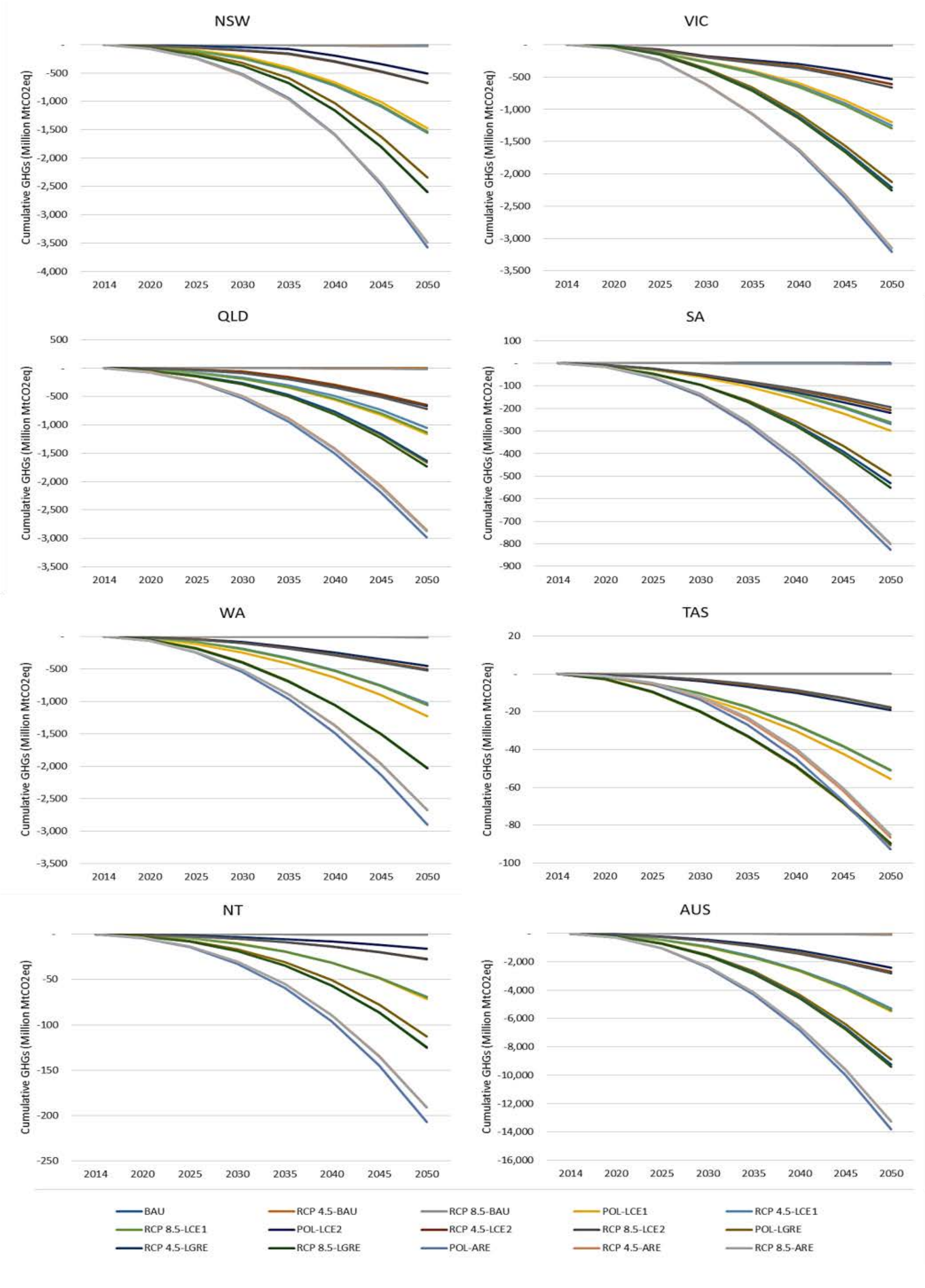

Figure 4. 24: Cumulative GHG Emission Compared to BAU Scenario.

4.5.3.2. Cumulative GHG Savings and the Cost of Avoided GHG Emissions

The environmental aspect can be further extended to account for the cumulative GHG emissions savings and cost of avoiding GHG emissions. The GHG savings are the cumulative emissions saved in the entire energy system, while the cost of avoided GHGs is the cost to decrease atmospheric GHGs, expressed as the dollar per tonne of CO_2eq not emitted compared to the BAU scenario. The results presented in Table 4.9 identify the least costly approach in reducing one tonne of CO_2. The results for GHG savings confirm our earlier results on GHG emissions, and demonstrate the importance of decarbonising Australia's energy system.

Table 4. 9: Cumulative discounted GHG Savings and Cost of Avoiding GHGs.

	Discount rate	POL-LCE1	POL-LCE2	POL-LGRE	POL-ARE
GHG Savings (Mill Tonnes CO2e)		6,295	6,044	10,289	16,535
Cost of Avoiding GHGs (U.S. Dollar/Tonne CO2eq)	5%	-56.7	-61.6	52.7	32.8
	10%	-20.7	-23.7	15.8	9.8

A CCS fossil fuel or nuclear pathway will result in a cumulative GHG savings nearly 3 times lower than the GHGs saved in a 100% renewable scenario. The cost of avoided GHGs indicates that under 5% and 10% discount rates, the POL-LCE1 and POL-LCE2 recorded higher net benefits, while the POL-LGRE and POL-ARE had higher costs. This occurred due to investments to enhance the penetration of alternative vehicles in the transport sector, such as EVs and PHEVs. This was a similar outcome from a study by (Di Sbroiavacca et al., 2016), in which the policy baseline and 20% abatement scenarios had higher costs in avoiding GHG emissions than the low- and high-CO_2 price scenarios.

4.5.3.3. Global Warming Potential and Indirect GHG Emissions

We extend our environmental analysis to examine sub-sectors and technologies within the demand sector with global warming potential from both direct and indirect emissions[50]. The results presented in Table 4.10 display the direct and indirect emissions

[50] The indirect emissions originate in the transformation sector, where primary and secondary energies are produced for the demand sector, but other GHG results do not account for the indirect emissions.

associated with energy consumption within the energy system. We also extended the results to include policy and climate scenarios. It can be observed in Table 4.9 that water heating, space conditioning and appliance operations in the residential sector account for the most emissions contributing to global warming by 2050. Moreover, space conditioning and lighting operations in the commercial services sector lead to the increased potential for global warming. The global warming potential for technologies in the POL-ARE scenario greatly decreases, and especially for space conditioning, which decreases threefold.

Under climate conditions, the global warming potential attributed to space conditioning was also three times lower in the POL-ARE than in the BAU scenario. The RCP 8.5 conditions also noticeably increase emissions from utility companies, such as electricity, water and gas services, in the POL-LCE1, POL-LCE2 and POL-LGRE scenarios. This can be attributed to increasing temperatures' effects on the operation of utility services, such as these services' energy consumption of electricity. The manufacturing and mining sub-sectors account for the highest indirect emissions in all policy scenarios, except in the POL-ARE. In the transport sector, the use of biofuels, improved efficiency standards, and a mode shift in the aviation industry can decrease the potential for global warming to less than its 2014 value. The penetration of EVs and PHEVs also contributes to decreasing emissions by five times the base year value.

Studies as Azad et al. (2015) posited that second-generation biofuels have better prospects as future transport fuels in Australia than first-generation biofuels. This can address issues in biofuel consumption, such as an increase in emissions and competition with land used for food crops, as aforementioned. Further, electrified vehicles have a place in Australia's future transport mix, but penetration rates have been low compared to sales in the European Union, United States and neighbouring China (Scutt, 2018). However, the introduction of these alternative transport technologies may compel consumers to drive more if they perceive that driving is more pleasant and saves more on fuel costs than commuting through public transport services (Bureau of Infrastructure, 2017d), such as buses that use CNG.

Table 4. 10: 100-Year global warming potential from demand sector plus indirect emissions.

Sectors Million Mt CO2-e	Sub-sectors/Technologies	2014	2050														
			BAU	RCP 4.5-BAU	RCP 8.5-BAU	POL-LCE1	RCP 4.5-LCE1	RCP 8.5-LCE1	POL-LCE2	RCP 4.5-LCE2	RCP 8.5-LCE2	POL-LGRE	RCP 4.5-LGRE	RCP 8.5-LGRE	POL-ARE	RCP 4.5-ARE	RCP 8.5-ARE
Agriculture	Agric., Forestry & Fishing	28.1	40.0	40.9	38.9	33.3	33.7	35.7	34.7	33.7	35.7	56.6	60.3	64.2	40.5	41.0	40.9
Commercial Services	Domestic hot water	1.9	2.0	2.3	2.2	1.2	1.1	1.2	1.2	1.1	1.2	1.0	1.0	1.1	0.0	0.0	0.0
	IT Equipment	74.7	73.6	73.7	62.5	38.4	35.0	37.1	36.6	33.2	35.3	31.5	29.3	29.7	3.3	4.6	4.5
	Kitchen/Cooking	9.1	16.0	18.0	18.0	13.3	13.4	15.1	13.4	13.4	15.1	12.0	13.6	15.1	8.7	7.9	7.9
	Lighting	131.3	129.3	129.6	109.9	67.5	61.6	65.2	64.3	58.3	62.0	27.4	25.5	25.9	0.5	0.7	0.7
	Other electrical process	12.5	12.3	12.3	10.4	8.0	7.3	7.7	7.6	6.9	7.3	6.3	5.8	5.9	0.5	0.6	0.6
	Other energy	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.0	0.0	0.0
	Other gas process	0.8	1.3	1.5	1.5	1.4	1.4	1.6	1.4	1.4	1.6	1.4	1.6	1.8	1.3	1.2	1.2
	Space conditioning	328.0	323.3	348.6	318.8	148.4	145.9	172.5	141.6	138.5	164.4	116.0	116.9	128.0	20.8	29.3	31.2
	Vertical transport	33.0	32.5	32.6	27.6	21.2	19.4	20.5	20.2	18.3	19.5	19.8	18.5	18.8	2.5	3.5	3.5
Electricity/Gas/Water	Own consumption	852.7	1,398.5	1,505.0	1,456.1	1,019.1	1,011.5	1,118.6	1,075.6	1,050.3	1,157.2	881.5	954.0	1,033.2	71.8	71.6	71.4
Industry	Construction	8.5	31.1	33.9	31.6	26.5	27.2	29.2	27.0	26.8	28.8	43.5	47.1	49.8	32.3	37.9	37.7
	Manufacturing	666.4	622.0	617.3	590.5	355.7	339.3	369.4	347.5	327.6	357.8	252.7	237.5	260.0	82.9	149.9	149.4
	Mining	352.7	730.5	781.3	741.1	430.7	429.4	471.6	434.9	420.7	462.5	260.7	284.0	308.8	67.3	155.0	154.5
Others	Other industries	0.4	0.6	0.7	0.7	1.0	1.0	1.1	0.9	0.9	1.1	1.6	1.9	2.2	1.8	1.8	1.8
Residential	Appliances	205.4	173.9	174.7	154.4	105.1	98.3	106.1	103.2	95.2	103.1	86.5	83.1	86.0	11.1	16.0	15.8
	Cooking	29.8	33.2	34.6	31.9	22.7	22.0	23.8	22.4	21.6	23.4	23.2	20.0	21.2	8.6	12.1	12.0
	Lighting	46.7	37.9	37.7	33.3	21.9	20.2	21.8	21.4	19.6	21.2	9.9	9.1	9.5	2.1	1.8	1.8
	Space conditioning	382.6	338.1	366.8	366.2	210.4	212.8	244.9	212.8	213.9	245.6	177.2	190.8	216.0	104.9	118.8	124.1
	Water heating	109.2	117.3	133.3	131.2	77.7	75.2	81.9	75.5	73.0	79.7	51.7	55.3	59.9	3.4	4.8	4.7
Transport	Aviation	27.3	64.7	66.1	65.9	47.8	47.8	49.2	47.8	47.9	49.3	23.3	24.5	25.4	11.2	13.4	13.4
	Maritime	4.4	4.6	4.7	4.7	3.8	3.9	4.0	3.9	3.9	4.0	7.4	8.4	9.1	7.4	6.7	6.6
	Other transport/postage	26.4	19.4	20.3	18.8	14.5	14.1	15.4	14.4	13.8	15.0	11.6	12.3	13.3	2.1	2.6	2.6
	Rail	24.2	15.3	15.5	13.6	10.6	10.5	10.8	10.6	10.1	10.4	14.7	12.0	12.2	13.5	13.1	13.1
	Road	234.8	255.9	263.1	257.8	170.9	168.9	177.9	171.2	168.6	177.7	187.0	180.0	186.0	39.9	63.2	63.2
Total		3,590.9	4,473.5	4,714.6	4,487.8	2,851.3	2,800.9	3,082.4	2,890.3	2,798.9	3,078.8	2,304.7	2,392.8	2,583.2	538.3	757.7	762.7

4.5.3.4. Decomposition Analysis of GHG Emissions

The change in GHG emissions was decomposed using the log mean Divisia index (LMDI) method for the study period (2014–2050). The LEAP model decomposed GHG emissions from the energy system into three factors (see section 4.3.2.5). First, the activity effect demonstrates the economic output's effect on GHG emissions. Second, the energy intensity effects measure energy efficiency improvements' effects on emissions based on the energy consumed. Third, the emission intensity effect is the emissions emitted from the energy consumed. The GHG decomposition results were compared to the BAU scenario, and Figure 4.25 presents this comparison for Australia's energy system. The results indicate that emissions intensity effects will contribute to an increase in GHG emissions by 108 million $MtCO_2eq$, while energy intensity effects are expected to contribute to a decrease in GHG emissions in the POL-LCE1, by 140 million $MtCO_2eq$ and 313.5 million $MtCO_2eq$, respectively.

Under climate change conditions, the activity effect increases GHG emissions, while the energy and emissions intensity effects decrease, leading to an increase in emissions by 2050. A comparison of POL-LCE1 and POL-LCE2 scenarios reveals the emissions intensity effect contributes more in the POL-LCE2, while the activity effect contributes less to the reduction of GHG emissions. The POL-LGRE scenario contributes 158 million $MtCO_2eq$ to emissions reduction by 2050. Under climate change in the POL-LGRE scenario, the end-year emissions increase from 370 to 422 million $MtCO_2eq$ in the RCP 8.5 climate scenario. The picture changes in the POL-ARE scenario, in which the three effects contribute to a decrease in GHG emissions.

Although the activity effect's contribution in the two climate scenarios under POL-ARE was half the value in the BAU, energy and emissions intensity still most contributed to emissions reduction, from approximately 760 million $MtCO_2eq$ in the base year to 138 million $MtCO_2eq$ in the end year. This agrees with work by Park et al. (2013), in which energy and emissions intensity contribute to a decrease in GHG emissions intensity under a sustainable scenario composed of large-scale renewable technologies. Our result implies that the increase in future GHG emissions under the alternative scenarios compared to the BAU will be largely caused by economic activities, except in the POL-ARE scenario. Further, energy and emissions intensity will contribute to a higher decrease in emissions by 2050 across the alternative scenarios than in the BAU scenario.

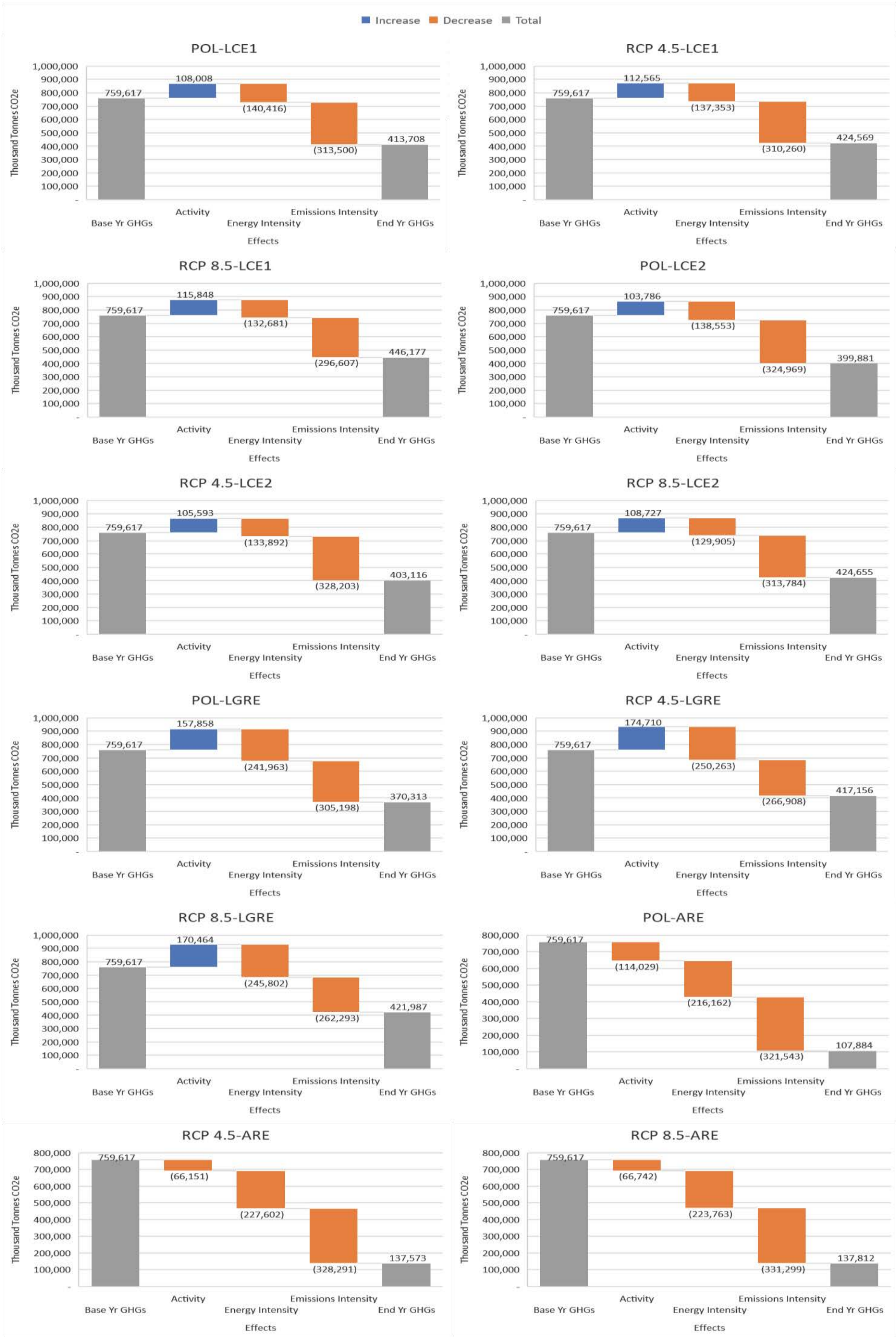

Figure 4. 25: Australia's Decomposition of GHG Emissions (2050 vs 2014).

4.5.4. Model Validation

In this section, we verify the validity of the Australian LEAP model using actual electricity generation data published by the Department of Environment and Energy (Energy, 2017b). The actual data was compared with the model output for electricity generation for the period 2014-2017. The results of the comparison are presented in Table 4.11, and show that the model predicted closely matched data for the base year (2014) and study period for electricity generation. The errors range between 0.00% and -0.10% across the states/territory and across the years, while the mean absolute percentage error (MAPE) was between 0.01% and 0.08%.

Table 4. 11: Electricity Generation Official Data and LEAP Data from 2014 to 2017.

	2014	2015	2016	2017	MAPE
LEAP-AUS	247843.38	252439.83	257402.59	260108.62	
Actual Data	247843	252391	257429	260155	
Error	0.00	0.02	-0.01	-0.02	0.02
LEAP-NSW	67295.43	64183.15	70262.22	70854.10	
Actual Data	67295	64159	70250	70876	
Error	0.00	0.04	0.02	-0.03	0.01
LEAP-VIC	52803.16	56665.51	54549.69	52845.37	
Actual Data	52803	56679	54562	52861	
Error	0.00	-0.02	-0.02	-0.03	0.03
LEAP-QLD	60479.97	68122.05	67354.13	70725.12	
Actual Data	60480	68117	67387	70736	
Error	0.00	0.01	-0.05	-0.02	0.02
LEAP-SA	13119.97	13037.31	13077.42	11616.03	
Actual Data	13120	13026	13082	11608	
Error	0.00	0.08	-0.04	0.07	0.06
LEAP-WA	36679.59	37793.92	38743.80	40477.86	
Actual Data	36680	37782	38737	40489	
Error	0.00	0.03	0.02	-0.03	0.03
LEAP-TAS	13999.46	9638.89	10352.33	10608.79	
Actual Data	13999	9631	10344	10601	
Error	0.00	0.08	0.08	0.08	0.08
LEAP-NT	3465.82	2999.00	3062.99	2981.34	
Actual Data	3466	2997	3066	2983	
Error	0.00	0.07	-0.10	-0.07	0.08

This implies a high correlation between the actual data and LEAP model electricity generation output for the years under observation. Therefore, the largest error for yearly electricity generation modelled in this paper should be ~0.10%, while the highest MAPE across the state and territory was 0.08%, and both were identified from the model output for Northern Territory. The possible reason for the slight differences between the actual and LEAP model data may be attributed to the assumption made in the BAU scenario, which may slightly change the course of electricity supplied. However, the outcome of the comparison is considerable because the errors can be considered minimal. Therefore, the useful policy implications can be drawn for the modelling results.

4.5.5. Comparison with Previous Studies

The main modelling outcome from this study is that meeting future energy demand triggered by CV&C will require a substantial amount of investment in energy technologies, while the cost of having a low carbon economy before 2050 is relatively small compared to the BAU case. Previous international studies using IAMs to access CV&C impact on the energy system include Seljom et al. (2011) who evaluated the impact of climate change on the Norwegian energy system and found decreasing demand for heating and increasing demand for cooling with limited climate impact on wind power and increased hydropower potential, leading to reduced system costs and lower electricity production costs. This contrasts with results from the current study where changes in demand for space heating contributes to increases in electricity generation costs.

Dowling (2013a) estimated the impact of climate change on the European energy system and found that climate impact on space conditioning demand was higher than supply side impacts for fossil fuel and nuclear sources. The impacts decrease for renewable energy with power output increase. Similarly, Mima and Criqui (2015a) examined the impact of climate change on the European energy system and found that demand increase is due to air conditioning, while heating demand, and thermal, nuclear, and hydropower output will decline by 2100. This study found decreasing output from fossil and nuclear power plants in Australia's future energy system up to 2050. However, increase in energy demand was not entirely attributed to CV&C impacts as demand from industry and electrification of the transport sector led to higher demand.

Jaglom et al. (2014) estimated the potential impacts of changes in temperature on the power sector in 32 US regions. The study found that total annual electricity production costs in 2050 are projected to increase by 14% due to increased demand for space conditioning which will increase GHG emissions by more than 5%, thus contributing to climate change. This study outcome supports the Jaglom et al. findings despite its focus on the Australian energy system. However, the costs associated with increased electricity production to meet rising demand were observed to decrease when a higher share of RETs are integrated into the power supply mix.

Similarly, McFarland et al. (2015) examined how projected rising temperature affects demand and supply of electricity in the US. They found that if global temperatures rise by 1.7°C before 2050 without emission mitigation measures, electricity demand will increase to 6.5% in 2050 with similar changes in emission, but the regional pattern was inconsistent. In this study, an increase in temperature-induced demand was found compared to the BAU, with an increase in emissions associated with power production up to 2050. However, the increases in demand were inconsistent across the regions. Energy policy measures were observed to mitigate emissions due to increasing energy demand across the seven states and territory analysed.

Meier et al. (2017) quantified temperature-induced changes in power plant emissions due to increased use of building air conditioning and found a 7% increase in demand and a 16-18% increase in emissions with a high level of regional variances. The state-level results in this study showed variations in emissions which increase in states located in the southern region of Australia and have lower emissions compared to the northern region, especially Tasmania. Staffell and Pfenninger (2018) developed an open framework to quantify the impacts of weather on electricity demand and supply for the British electricity system. They found that year-to-year variability of net electricity demand will increase 80% by 2030, but renewable power output will exceed demand as early as 2021. In this study, renewables were found to meet growing demand and fill the power supply gap due to the decline in thermal power output.

For comparison with regional studies, Table 4.12 highlights two previous Australian based studies and compared their BAU results with the BAU from this study. It is observed that the capacity and power generation of gas power plants were higher in this study compared to others. This is because the BAU scenario was modelled after the

AEMO neutral base case, while other studies did not apply similar projections. Also, the lower capacity of the coal power plant conforms to the scheduled retirement of coal power plants mostly in the NEM regions. Similarly, energy demand was observed to be higher than previous results and this can be attributed to the structure of the bottom-up model applied in this study, which was developed to model a detailed description of the Australian energy system. Therefore, some sectors, such as industry, include three subsectors (manufacturing, construction, and mining), and residential and commercial include space conditioning demand, while electricity generation was expanded to include other utility consumption, such as gas and water supply.

Table 4. 12: Comparison of 2050 BAU result with previous studies.

Capacity (GW) / Electricity Generation (TWh/year)			
	Syed (2014)	Teske et al. (2016)	Current study
Coal	- / 214	30 / 254	10 / 69.6
Gas	- / 48	8 / 48	33.6 / 240
Oil	- / 3	1 / 1	-
Diesel	-	1 / 2	1.3 / 7.1
Hydro	- / 18	7 / 18	8.5 / 69.7
Wind	- / 33	15 / 33	13.8 / 76.5
Bioenergy	- / 6	1 / 6	0.8 / 4.3
Large-scale Solar PV	- / 6	4 / 6	13.6 / 74.3
Large-scale Battery		-	0.2 / 1.1
Geothermal	- / 4	-	-
Total	- / 332	67 / 368	81.8 / 542.6
Energy consumption by sector (PJ)			
Transport	2,723	2,542	2,473
Industry	-	2,417	3,252
Other sectors	-	1,079	102
Electricity generation	2,278	-	3,591
Agriculture	157	-	198
Mining	1,211	-	Included in industry
Manufacturing	1,618	-	Included in industry
Commercial & Residential	554	-	1,496
Total	8,541	6,038	11, 112

Note: Rooftop solar was excluded

This study extended the comparison to Australian studies modelling the large integration of renewables to the future energy system as presented in Table 4.13. Previous studies used various assumption which includes a 'like-for-like' replacement of power plant and least-cost approach. The ARE scenario in this study is based on resource availability, capacity credit, which increased after retirement of fossil fuel plants, and endogenous capacity addition to meet demand under climate change constraint.

This study differs from previous works which examined the combined impacts of CV&C on the future energy system in a range of countries (including Australia):

- Previous studies generally overlooked the transition of technologies in sectors with less or non-temperature sensitive demand. This includes the transport sector, which is becoming electrified with massive rollout of EV and PHEV;
- Most CV&C impact studies focus on smaller countries with a similar pattern of climate induced demand and a uniform electricity market. This study, however, examines the impacts of CV&C on a country with a large geographical area and complex energy markets consisting of two major (NEM and SWIS) and two minor (NWIS and I-NTEM) markets operating independently.
- A critical mass of the literature focuses on countries located in North America, Europe, and northern Asia, which are characterised by higher winter loads and changes in solar power supply. However, fewer studies have concentrated on countries located in the Southern Hemisphere, where most of the world's population resides, with low heating loads and seasonal variations in demand;
- In comparison to Australian studies, this study went further to examine the implication of CV&C on interregional electricity trade, sales revenue, generation cost, and LRMC, which can advise electricity companies on potential regions for investments and management of future energy technologies.

Also, the cost-benefit analysis, which has not been considered in previous Australian studies can assist the government in policy making, while the results of direct and indirect emissions can enable policymakers to identify areas of emission mitigation.

Table 4. 13: Comparison of advance renewable economy scenario with other renewable only scenario energy studies for the Australian NEM.

Generation technology	Capacity (GW)/Electricity Generation (TWh/year)								
	NEM					SWIS		AUS	
	AEMO Operator (2013)[a]	Elliston et al. (2013)[b]	Lenzen et al. (2016)[c]	Blakers et al. (2017)[d]	Current study	Lu et al. (2017)[e]	Current study	Teske et al. (2016)[f]	Current study
Rooftop solar PV	17/23	Included in large scale solar PV	4.1/8.5	17/23	21.2/64	2.8/4.2	2.8/12.9	Included in large scale solar PV	25.1/79
Large scale solar PV	16.5/45	29.6/41	23.1/29.9	6/13	25.7/74	1.5/2.3	1.5/6.9	166/266	26.6/83
Wind	6/20	34.1/94.8	52.2/82.5	45/136	16.1/33	4.0/8.2	3.5/16	80/180	18.4/49
Pumped storage	Included in hydro	2.2/0.5	-	16/16	Included in hydro	1.5/1.9	Included in hydro	-	Included in hydro
Hydro	8/13	4.9/11.5	2.6/7.5	7.4/17	6.4/52	-	1.0/8.5	8/19	9.7/61
Biomass	4/30	-	-	0.6/1	2.5/8	-	-	20/74	2.5/8
Biogas	9/5	22.7/12.7	19.6/16.5	-	-	1.5/1.7	-		-
Battery Storage				-	7.7/22	-	1.5/6.8		9.2/29
Concentrating solar thermal	12.5/45	13.3/43.9	61.2/140	-	11.50/	-	0.7/6.1	16/78	8.1/48
Geothermal	9/65	-	-	-	3.2/9	-	0.5/1.6	10/51	3.8/12
Wave/Ocean	0.5/2	-	-	-	11.5/1.6	-	0.3/0.5	13/50	2.7/2

Note: [a] is from scenario 1 (rapid technology transformation and moderate economic growth) by 2030; is from low cost scenario with 5% discount rate; [c] is from the study least cost simulation; [d] is from 100% renewable energy scenario; [e] is from 100% renewables scenario; [f] is from advance renewables scenario.

4.6. Discussion

4.6.1. Implication for Australia

This study has a range of implications for energy consumers, power companies, and policymakers in Australia. First, consumers adjusting to an increase in demand for space conditioning implies additional expenditures on thermal comfort. Although the annualised cost of replacing inefficient appliances have long term benefits in year-to-year energy savings, consumers' willingness to switch to new efficient appliances will require improved participation of the Australian government in terms of policy support. For example, policies aimed at reducing prolonged AC usage during peak summer months will need to be developed, while incentives, such as subsidies on energy efficient appliances will need to be provided to low-wage consumers who may not be able to afford the cost of switching. These actions can be extended to the transport sector where government subsidies on EV and HFCV can be an incentive for consumers to move to cleaner transport modes. This study demonstrates through its cost-benefit analysis that the benefit gap is wider when penetration of alternative vehicles and renewable transport fuels deepens.

Second, the outcome of this study shows that power generation companies will face three choices: stick to fossil fuel with CCS adaption or nuclear power, lower investment in grid electricity expansion while supporting the demand side program to boost the number of prosumers, and massively invest in RETs while retiring fossil fuel plants before 2045. Power plant investments are energy intensive and companies will have to deal with the direct and indirect impacts of CV&C in the coming years. The results show that while increased demand will result in capacity expansion, CV&C will affect power company profits as the two RCPs showed higher electricity generation costs and lower revenue returns. Also, lower discount rates boost investment in the power sector, while the sensitivity analysis indicates that higher investment in renewables will ensure an economy more resilient to changes in fuel prices and investment costs.

The future of fuel prices is uncertain, while the cost of fossil fuel technologies is narrower than renewable energy systems. This is because replacement of thermal plants is based on stable fuel prices, and the penetration of renewables follows a downward trend of investment costs in the future. However, companies may be obliged to shift to renewables as they face international natural gas and coal prices. The commencement of liquefied natural gas terminals in Queensland and gas export to the Asian market has led to higher power prices as companies pass down the cost to the final consumers. If government policies succeed in bringing down power prices, then the fossil fuel generating fleet will have higher operating costs and investment in large-scale renewables will become more attractive.

Third, Australian policymakers will have to address CV&C impacts through adaptation policies to cushion the effect of climate change on consumers, while adapting or transforming the current energy system to climate change. On the demand side, this includes modernising building structures to accommodate improved insulation systems and energy efficient appliances. On the supply side, policymakers might face stiff resistance in the short-term as most generation technologies, such as natural gas and coal power plants, have a long life and investments will have to be recouped. The previous government of Malcolm Turnbull failed in the realization of its proposed energy policy, the National Energy Guarantee (NEG), and his successor, Scott Morrison, has focused on cheap electricity prices and will make efforts to reduce emissions (AAP/SBS, 2018).

However, it is unclear how the government intends to meet its climate target as it recently backed fossil fuel power plants in defiance of the recent IPCC climate warming, which suggests the phasing out of coal before 2050 (Karunadasa et al., 2010). Recently, Australia's emissions have been on the rise for the third consecutive year and an environmental report suggests higher emissions from transport and electricity generation (Environmental, 2018). This study shows that if the government refuses to implement policies to replace the current system with sustainable sources, the economic cost will be more than US$3.9 trillion by 2050 with higher costs of electricity generation and cumulative GHG emissions. Therefore, the outcome of this study should be considered in implementing future climate and energy policies in Australia.

4.6.2. International implications

In an international context, various countries share similar characteristics with Australia in terms of abundant renewable energy resources, high fuel prices, and vulnerability to climate change. Although Australia has abundant renewable energy resources, higher fuel prices and CV&C impacts should make an economic case for the transition towards a clean energy system before mid-century. The European Union has made advances towards a decarbonized energy system, and recent publications (Bonjean Stanton et al., 2016, Tobin et al., 2015, Tobin et al., 2018) indicate severe CV&C impacts on the region's energy sector. This creates a need to move the region towards a climate resilient energy system. This need, in terms of energy and climate policy, is the missing gambit to move Australia towards an advanced renewable economy.

Australia, like other fossil fuel dependent nations, spends a huge amount on fossil fuel. The US spends over US$20 billion per year on fossil fuel subsidies (Nuccitelli, 2018), while Australia spends about AU$5.6 billion per year (Vorrath, 2015). This amount will increase considering the impacts of CV&C as this study indicates. Countries, such as Sweden, Costa Rica, Germany, Denmark, and China, among others, have either advanced to 100% fossil fuel-free or they are on the pathway to total decarbonisation. The money spent on subsidies could be channelled to large scale renewables, which will not only cut emissions as modelled in this study, but result in economic savings by up to 88% in 2050. Studies, such as Sampedro et al. (2017), Li and Jiang (2016) concerning China and the EU, respectively, found that redirecting fossil fuel subsides to renewables could promote low-carbon technologies, but highlighted the inclusion of energy price reforms to reduce energy rebound effects.

As climate change is anticipated to encourage adaptation of sustainable energy sources, resource availability becomes a focal point. Australia's use of renewable energy resources (e.g. solar) is comparably higher than most countries. This may lead to differences in generation costs when compared to other countries with limited renewable resources and may hinder the progress towards a climate resilient energy system. Finally, Australia's current and future population distribution is likely to be in favour of the extension of transmission lines with little resistance by the populace as compared to countries with higher populations. This will become necessary as a new power infrastructure will be built to accommodate the rising energy demand associated with CV&C in the long-run.

4.6.3. Towards a coherent energy and climate policy design

Designing a coherent energy and climate policy will require a clear policy objective, which aims to reduce GHG emissions and adapt the future energy system to CV&C impacts. Although CCS applications in industries and power plants were observed to reduce emissions in this study, the cumulative emission and technology costs were somewhat higher than a renewable dominated energy system. To most energy companies, reducing GHG emissions may appear costly and these costs are be passed down to the final consumer. Accordingly, the high cost may also affect products shipped out to the international market. For example, higher energy prices may be reflected in Australian products, which may have to compete with goods produced in countries with no enforced emission reduction policies. Therefore, a coherent energy and climate policy design should connect domestic policies with international obligations.

The Australian government's current stand is to reduce energy prices and meet its Paris climate agreement target of reducing emissions by 26% to 28% on 2005 levels by 2030. Since the government has rejected calls to phase-out coal power plants following the IPCC report, climate policy measures should be adjusted to accommodate long-term transition to a fossil fuel free economy by 2050. This can be achieved through a policy framework which aims to combine GHG emissions reduction and minimise the impacts of CV&C on the power demand and supply sector. The model in this study is a good example of studying the combined effect of CV&C along with the cost implication. Before developing such a policy framework, it is necessary to have a clear picture of the adjustment to be made to the current energy system to meet future climate conditions.

Generally, this includes power system upgrades and deeper penetration of alternative energy sources and technology, which includes newer transport systems, such as EV and HFCV. Another aspect is the lack of an effective long-term climate and energy policy, which has been a contributing factor to higher energy prices and an unreliable power system in the face of CV&C. The failure of the proposed energy policy (the NEG) implies that policymakers will have to develop a new energy policy that will be acceptable and implemented across the states and territories in Australia. The new policy should include components of adaptation to CV&C impacts on the demand side, in connection to supply side climate change adaption. Once this issue has been addressed, the focus should move to reducing high wholesale electricity prices, which will be achieved through large scale renewable generators that receive fuel free. This framework will align the Australian government position with its international obligation on emission reduction, while protecting its citizens against increased expenditures due to climate change.

4.7. Conclusion

This study assessed the techno-economic implications of long-term energy policies and climate variability on the future energy system in Australia. Incorporating the effects of CV&C through estimates from previous studies into the LEAP mode, the analysis showed substantial impacts on energy demand, as well as impacts on power sector capacity expansion, investments, revenue generation, and associated direct and indirect emissions. Under the BAU scenario, CV&C will result in an increase in energy demand by 72 PJ and 150 PJ in the residential and commercial sectors, respectively. The temperature induced increase enlarges the non-climate BAU demand, which will increase threefold before 2050.

Higher demand means additional power generation and associated investment in capacity expansion which is affected by CV&C. Under the non-climate BAU, there is an expansion of installed capacity to 81.8 GW generating 524.6 TWh. Due to CV&C impacts, power output declines by 59 TWh and 157 TWh in RCP 4.5 and RCP 8.5 climate scenarios. This leads to an increase in generation costs by 10% from the base year, but a decrease in sales revenue by 8% and 21% in RCP 4.5 and RCP 8.5, respectively. Higher demand and increased fuel consumption due to a decrease in efficiency due to CV&C leads to increased GHG emissions, which contributes to climate change. The effect of CV&C under the BAU scenario results in an increase in power sector GHG emissions by 40-73 MtCO2eq by 2050. This implies that energy demand and supply can be substantially affected by CV&C.

Other analyses conducted include energy savings for the transport sector where alternative vehicles, such as EV, PHEV, HFCV, and biofuels contributed to a decrease in primary energy demand, but a shift in demand to secondary fuels, such as electricity, which can be generated from a renewable source. Interregional trade of electricity commodity reveals that CV&C will result in increased demand and decreased power output in the NEM in Australia. The LRMC results reveal that lower investment in grid technologies, especially fossil fuel, and an increase in the capacity of renewable energy can potentially decrease wholesale and retail electricity prices. Cumulative cost-benefit analysis of the alternative scenarios compared to the BAU indicated that the energy efficiency policy in the LGRE scenario will result in an economic benefit of US$3.9 trillion by 2050, and the benefits increase to US$4.9 trillion in a higher renewable energy scenario.

These results highlight the need for power companies and policymakers to account for future CV&C impacts in energy sector planning. This study shows that ignoring the influence of CV&C may result in underestimation of future energy demand and installed capacity in Australia. This study shows that although the policy options to reduce demand, emissions, and CV&C impacts may be expensive in the short-run, the long-run benefits in terms of cost savings, emission reductions, and power sector management supersede the short-term costs. Therefore, it is important for power companies and policymakers to capture the effect of CV&C when comparing the BAU with alternative mitigation scenarios.

This study is not without limitations, as the scenarios presented are not exhaustible, and other policy pathways can be further explored and compared to our results. The study could be improved by exploring consumers' acceptance of alternative technologies, as well as the estimates embedded in the LEAP model. Further, this study's approach could be extended to examine climate change's impact on wind and hydro power plants, and further analysed in case studies from other countries. This will enhance the approach developed in this study and improve LEAP modelling studies.

Chapter 5: Are Emission Reduction Policies Effective Under Climate Change Conditions? A Backcasting and Exploratory Scenario Approach Using the LEAP-OSeMOSYS Model

Chapter 3 estimated future temperature sensitive electricity demand and chapter 4 modelled the dynamic interactions between energy policies and CV&C impacts. This chapter explores least cost electricity generation technologies and identifies effective GHG emission reduction policies under climate change conditions for Australia (Figure 5.1).

This chapter has been adapted into a manuscript: Emodi, N. V., Chaiechi, T., & Beg, A. R. A. (2019). Are emission reduction policies effective under climate change conditions? A backcasting and exploratory scenario approach using the LEAP-OSeMOSYS Model. *Applied Energy*, 236, 1183-1217.

Initially, this manuscript (chapter 5) was prepared as a manuscript for a conference paper titled Emodi, N. V., Chaiechi, T., & Beg, A. R. A. (under consideration). Analysis of a Constraint-Optimized Electricity Generation Model for the South West Interconnected System of Western Australia. Submitted to *International Journal of Global Energy Issues* (Manuscript ID: IJGEI-232698). However, the manuscript was submitted to journal and is under peer review. The improved and expanded version of the paper is now published as chapter 5.

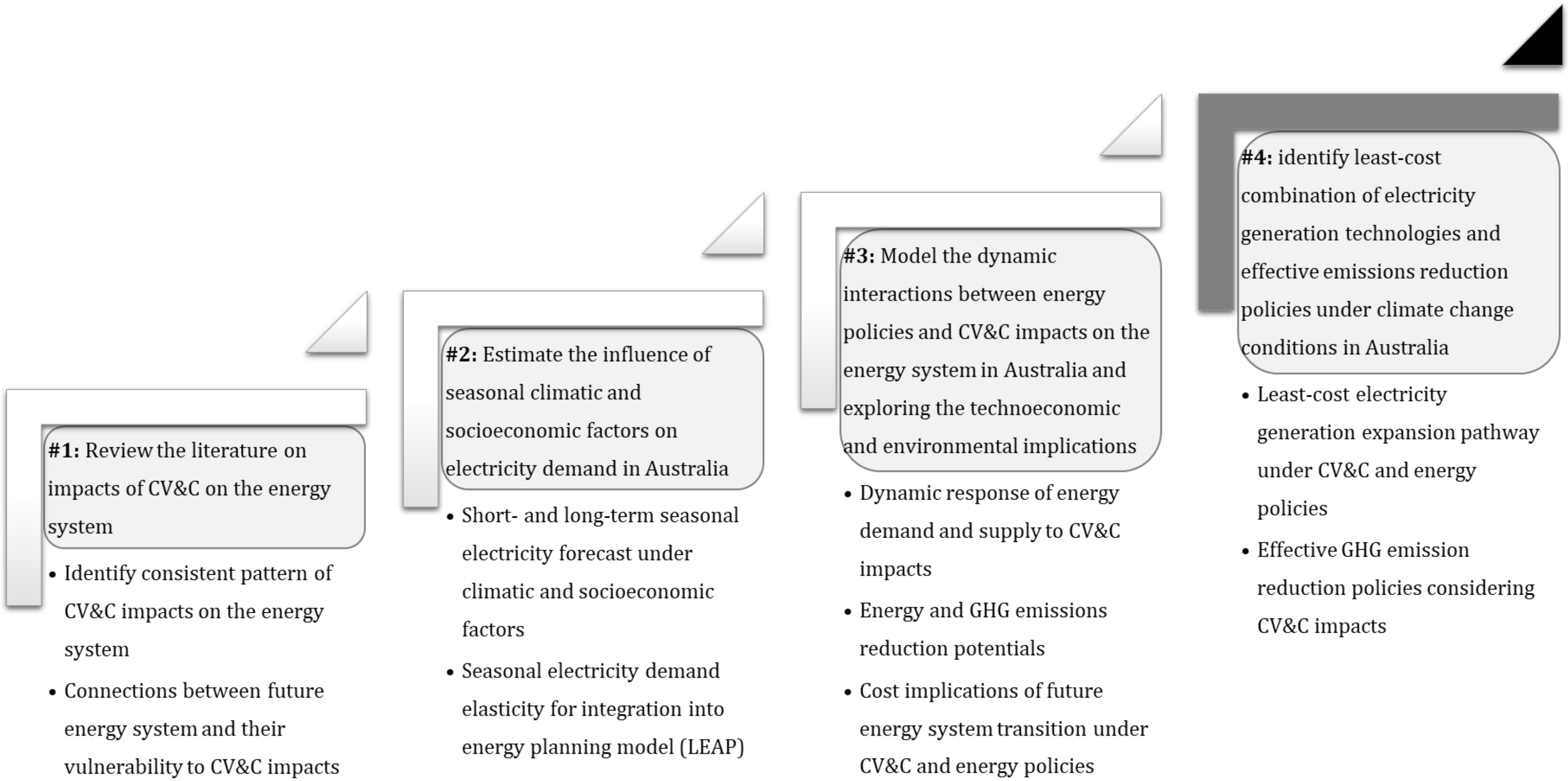

Figure 5. 1: Progress through the thesis: Research Aim #4.

5.1. Abstract

The power sector exercises huge impacts on global warming through emitted greenhouse gases [GHGs], with Australia not an exception. Over the years, the effectiveness of policies that have emerged to curtail GHGs emissions from electricity generation seem barely investigated. To address this gap, the study identifies potential emission reduction policies and climate change scenarios for the Australian power sector by applying approaches from combined backcasting and exploratory scenario. The Long-range Energy Alternative Planning (LEAP) system and its integrated Open Source Energy Modelling System (OSeMOSYS) was used for optimisation analysis. Results identified cost optimisation scenarios as a least-cost generation pathway with less climate change impact, followed by renewable energy target and energy productivity scenarios. Economic analysis shows that emission reduction policy will result in added cost to the economy, while carbon tax policies will yield economic benefit in installation cost, resource savings and environmental externalities reductions by 2050. The environmental analysis reveals that emission reduction policy will increase cumulative emissions, while future temperatures may double the emissions from the base case scenario. This study conclude that future low-carbon pathways lie in clean energy substitutions and innovative energy policies, while global warming raises the need to switch to clean energy technologies early.

5.2. Introduction

Post-industrial revolution has made energy infrastructure a vital component for economic growth and development (Garg et al., 2015). Yet it comes with consequences for our climate. One of which is increase in greenhouse gas (GHG) concentration in the atmosphere (Seljom et al., 2011). In 2015, the International Energy Agency report identified electricity and heat production as highest contributors to global carbon emissions (Statistics, 2017c). Whereas, efficiency of the electricity sector in terms of production and distribution is in-turn affected by impacts of climate change (Mideksa and Kallbekken, 2010, Chandramowli and Felder, 2014, Bonjean Stanton et al., 2016, Peters et al., 2006, Colman, 2013). These impacts are typified in temperature variability on electricity generating systems such as nuclear power plants (Linnerud et al., 2011, Durmayaz and Sogut, 2006), solar photovoltaic (PV) (Liu et al., 2014, Ma et al., 2016a, Wild et al., 2015), hydropower and wave technologies (Majone et al., 2016, François et al., 2016, Karlsson et al., 2016, Madani et al., 2014, Reeve et al., 2011a), and gas power plants (Hoffmann et al., 2013, Zheng et al., 2016). Thus, policy concerns in this regard hinge on optimising power generation and distribution, amidst the challenges of climate change, while ensuring the reduction of GHGs emissions (Ruth et al., 2015, Mohor et al., 2015, Qi et al., 2016, Lin et al., 2010, de Lucena et al., 2010, Zhang et al., 2016, Ataei and Ebadi, 2015, Awopone and Zobaa, 2017, Ciscar and Dowling, 2014, Maran et al., 2014a). It is the dearth of such policies either on the short, medium or long term (Cortekar and Groth, 2015) that will effectively manage this dilemma likened situation that has given rise to this study.

Among productive efforts curtailing the reduction of GHGs emissions from electricity generation is optimisation of the electricity sector (Ataei and Ebadi, 2015, Chatzipoulidis, 2012). This approach examines the least cost electricity generation pathways for an optimal energy mix and dispatch system (Augutis et al., 2015, Awopone et al., 2017a). Building on the gains of optimisation is carbon tax. It influences propensities of energy sectors toward renewable energy, and generates revenue for the government (Awopone and Zobaa, 2017, Ciscar and Dowling, 2014). While it is okay appreciating these policies aimed at reducing emissions of GHGs, of much concern on the other hand is the possibility of maintaining stable power generation which is threatened by global warming (Maran et al., 2014a, Cortekar and Groth, 2015). This is because all consequences seem to be interconnected. The more productive gains at one end, could lead to devastating loss at the other. So, policies here are expected to provide for the benefits of all consequences.

Creating efficient energy systems is amongst contemporary global actions, as typical in the Paris Climate Agreement in 2016. The world aims at limiting global warming to less than 2^0C while aiming for 1.5^0C before 2100 (UNFCCC, 2015, UNFCCC, 2016). Countries in the European Union (EU) have set up plans to move to a low-carbon economy by 2050 and intend to achieve this feat by cutting emissions to 80% below 1990 levels (Commission, 2018). Other countries making commitments include Australia, Brazil, Canada, Indonesia, Japan, among others (Authority, 2015). While these benchmarks are praised on one hand, they are likewise considered ambitious on the other. For instance, there are predictions of increase in electricity demands due to hotter summer and cooler winter (Mima and Criqui, 2015b, Criqui and Mima, 2012, Labriet et al., 2015, Dowling, 2013b), which further question the rationale that hope to cut GHGs emissions on which electricity generation thrives. Thus, the question of readiness and affordability of renewable energy would also contribute to the argument.

In lieu of the foregoing, it becomes important for innovations around power systems to make plans for accommodating both likely and unlikely changes of future weather conditions. In achieving this, the study anchors long term energy models. Variants of energy system models adopted to examine future energy pathways are well applied across literature (Jebaraj and Iniyan, 2006, Bhattacharyya and Timilsina, 2010, Bosello and De Cian, 2014, Chandramowli and Felder, 2014, Heather Haydock and McCullough, 2017). Common models identified include Long-range Energy Alternatives Planning (LEAP), Emissions Prediction and Policy Analysis (EPPA), Prospective Outlook on Long-term Energy Systems (POLES), MARKet ALlocation (MARKAL) and TIMES models. These energy models have various data requirement and address various energy system issues. However, models such as LEAP incorporates an optimization feature named, Open Source Energy Modelling System (OSeMOSYS) (Howells et al., 2011, Rogan et al., 2014). It produces a policy framework that will optimise the energy sector on short and long terms, and at same time manage climate change threats, while enabling GHGs reduction strategies. The OSeMOSYS has also been linked to TIMES and PLEXOS to analyse short-term variability on future capacity investment decisions (Labriet et al., 2015).

In this study, the LEAP-OSeMOSYS optimisation model and its methodologies were synthesized to simulate least-cost electricity generation pathway, while considering climate change conditions in Australia. Heedless the existence of other energy system models available, the LEAP-OSeMOSYS model was selected for this research. Its selection was justified owing to its simplicity, transparency, flexibility, and ability to optimize future energy system. For instance, the model provided the opportunity of inputting estimates from econometric and climate models. This helped the OSeMOSYS optimisation model fit in with its policy scenarios, while LEAP concentrated its analysis on potentialities for emission reduction and electricity generation under climate change conditions. The synthesis of both models, in addition to drawing from the approaches of backcasting and exploratory scenario is novel in energy studies, and particularly in Australia. This is in exception of LEAP, which has been widely used since the late 1980s for energy policy analysis and climate mitigation assessment in more than 32 countries (Heaps, 2016).

Australia was selected for this study due to its distinctive electricity sector made up of two major energy markets – the National Electricity Market (NEM) and South West Interconnected System (SWIS) of Western Australia (WA). The sector also accommodates two minor energy markets – the North West Interconnected System (NWIS) of WA and Interim Northern Territory Electricity Market (I-NTEM) of Northern Territory (NT). NEM covers Australia's major population with 85% of total electricity consumption, while SWIS of WA makes up 13% of the national electricity consumption. NWIS and I-NTEN are smaller networks that make up 2% of total electricity consumption in Australia as illustrated in Figure 5.2 (panel A). Australia's electricity mix in 2016 was dominated by fossil fuel with 85% share, while renewable energy makes up 15% (including bagasse and biogas) as shown in Figure 5.2 (panel B). This presents some challenges for Australia to meet its IPCC obligation in terms of emission reduction (Greg Bourne et al., 2018).

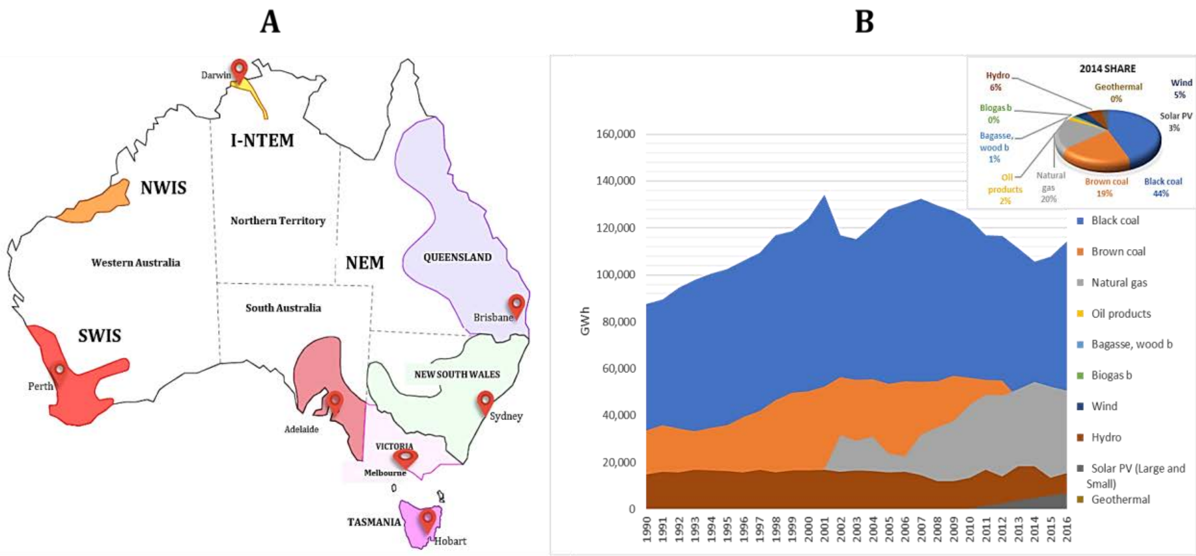

Figure 5. 2: Location of Australia's four electricity Market (panel A) and Electricity Generation by Fuel Source (panel B).

Source: panel A: (Palmer, 2017), panel B: (Energy, 2017b)

For the purpose of reducing GHG emissions from the power sector as well as encourage diversification, affordability and reliability of the power sector, it is important to examine how emission reduction policies can be implemented without reducing electricity supply whose demand will surge given future climate change predictions (Ahmed et al., 2012, Emodi et al., 2018, Howden and Crimp, 2001, Aghdaei et al., 2017, Khan et al., 2013, Wang et al., 2010). This will enable policymakers identify policies that can help foster clean energy and scale up decarbonisation in future power sector of Australia (Murphy, 2018). Hence the combination of backcasting, exploratory scenario, and the LEAP-OSeMOSYS optimisation model. It is anticipated that findings will impact energy and power related policies, and future research endeavours along this path. The rest part of this paper is organised as follows. Section 2 presents a review of the literature and study contributions. Section 3 describes the scenario and modelling approach of this study. Section 4 presents results of the study which includes technical, economic and environmental analysis. Section 5 sets out the discussion and Section 6 concludes the study with future directions.

5.3. Literature Review and Study Contributions

5.3.1. Literature Review

Over the years, studies examining least cost power generation expansion options, with application of different optimisation models, have increased. This is due to the increased pressure faced by policymakers and power companies to respond more effectively to several energy-environmental related issues, such as energy security, energy sector decarbonisation, and climate change. Optimisation models are effective tools for identifying optimal strategies within a complex power system. The models are used for both optimisation of energy system planning and associated GHG emission mitigation (Zeng et al., 2011).

It is important to note that some large-scale optimisation modelling system have been likewise applied across studies. For example, the BESOM[51] can identify the optimal mix of energy resources, technologies and investments based on low system cost (Chen

[51] Brookheven Energy System Optimisation Model

and Wu, 2004). Following the BESOM optimisation model is the TESOM[52] which supports energy management (Tessmer et al., 1975). The EFOM[53] is an engineering-oriented bottom-up model for energy management system planning (Tan et al., 2010, Vaillancourt et al., 2008). The MARKAL can be used for large scale, techno-economic analysis of the energy system. The MENSA[54] was established to identify optimal combination of energy demand and supply technologies with the objective of the lowest cost to the economy (Stocks and Musgrove, 1984). Other models include POLES (Mima and Criqui, 2015a, Dowling, 2013a), TIMES (Labriet et al., 2015), PRIMES[55] (Mantzos, 2009) and OSeMOSYS which is a full-fledged, open source systems optimisation model for long-run energy planning (Howells et al., 2011).

The OSeMOSYS is also integrated with the LEAP model and have been used to develop optimal power generation pathways in various countries (Rogan et al., 2014, Ataei and Ebadi, 2015, Awopone et al., 2017a). However, with the increase in global warming and its impact on the power sector, most researchers have extended optimisation analysis to examine least cost electricity generation pathways under climate change. This does not only expand our understanding on how future climate conditions may alter the configuration of future energy technologies, but help identify effective emission reduction policies capable of mitigating GHG emissions, while adapting to climate change.

Earlier studies on this subject include de Lucena et al. (2010) who identified least-cost adaptation measures for a set of projected climate change impacts for the Brazilian power sector from 2005-2035. The study used a combination of MAED (Model for Analysis of Energy Demand) and LEAP for demand side modelling and MESSAGE (Model for Energy Supply Strategy Alternatives and their General Environmental Impact) model for energy supply optimisation. Their simulation results show that additional electricity generation capacity would be required to compensate for loss of reliability in Brazil’s power generation system. Their results also show that the power system will be required to generate additional 163 TWh and 153 TWh per year in the A2 and B2 climate scenarios, respectively.

[52] Times-stepped Energy System Optimisation Model
[53] Energy Flow Optimisation Model
[54] Multiple Energy System of Australia
[55] Price-Induced Market Equilibrium System

Another study is that by Schlachtberger et al. (2018). They focused on underscoring the influence of weather data, cost parameters and policy constraints. They considered effects of the three mentioned elements on cost optimal scenarios, and likely influence they exercise on a long-run advanced renewable electricity system of 30 European countries. Additionally, they adopted a techno-economic optimisation model to their study. Their results show that total system costs are only weakly affected by the choice of input weather data or changes in capital costs. Also, emission constraints show that a wide range of CO_2 emission limits helps to to understand the mechanisms in the cost-efficient interplay of different technology options along the pathways towards a low-carbon future energy system.

Similarly, Schlott et al. (2018) investigated the impact of climate change on wind, solar, and hydro resources. They considered a highly renewable and cost-optimal European power system up to the year 2100. Climate change was observed to influence the optimal power system structure as wind, PV and hydro resources tend to be affected by global warming. Albeit the discovery that consequences for cost-optimal renewable power system may differ across regions in Europe due to climate variability. They concluded that the total system costs will be on increase until 2100. It was quite interesting to know that the different climate models they adopted were in contradiction as they converge toward the end of the century.

In addition to the foregoing, de Queiroz et al. (2019) analysed the impact of climate change on revenues of hydropower plants in Brazil. The simulation results show that climate change scenarios can impact hydropower revenues, specifically, the southern region. The entire process draws on advantages from the changing climate, which is due to a significant increase in subsystem assured energy. However, other regions were projected to have decrease in assured energy up to 2030 which will have a RCPative impact on hydropower revenues. These studies are generally in agreement that least-cost pathways for electricity generation consist of higher integration of low carbon technologies, heedless of climate change increasing system cost.

Besides the few studies identified above, other optimisation studies have explored decarbonisation pathways through the introduction of emission reduction policies. They include, Jacobson et al. (2015). The researchers used a grid integration model to identify low cost grid reliability solution to 100% penetration of intermittent wind, water and solar PV for the US energy sector. The results reveal an equilibrium between power supply, load, and storage dynamics. Solar and wind were complementary seasonally and diurnally, and the social cost for full system was observed to be much less than fossil fuel.

Pleßmann and Blechinger (2017) developed and improved a power system model, *elesplan-m*, to model the techno-economical optimal transition pathway for the EU to meet its GHG emission targets by decarbonising its power sector by 2050. The results suggest that the EU's reduction targets could be achieved by investing 403 billion EUR until 2050 in large scale renewable energy sources. Power supply system was largely composed of wind power (1485 GW) and PV (909 GW), which was supported by 150 GW hydropower and 244 GW gas power. Also, 432 GW of storage and 362 GW of transmission capacity were required for electricity distribution across the region.

Further, a different study by Plessmann and Blechinger (2017) modelled least-cost decarbonisation pathway for South-East European power system using the *elesplan-m* model. The results disclose that the region needs to increase its solar PV capacity to 120.7 GW, wind power capacity to 92.4 GW and transmission capacities to neighbouring countries to 32.7 GW until 2050 to achieve EU's GHG emission reduction targets. The study showed that transforming the power system require an average annual investment of about one billion EUR in the region. On the other hand, Schlachtberger et al. (2017) assume a CO2 emission limit of 5% in terms of 1990 levels as a constraint for the system optimisation in Europe. The simulation results show that a 5% cap on emissions correspond with a CO2 shadow price of 180 V/(tonne-CO_2) for both a scenario with optimal and moderate transmission expansion. This shadow price indicates the carbon dioxide price necessary to obtain the corresponding reduction in emissions in an unconstrained market. For a scenario without transmission between European countries, CO2 shadow price rises to 319 V/(tonne-CO_2), underlining the benefit of transmission for a low-emission electricity system.

Furthermore, in Yukon Territory in Canada, Chen et al. (2018) developed an inexact optimisation modelling approach for supporting regional energy system decision-making and GHG emission mitigation under uncertainty. Results for the scenario analysis reveal that for the 25-year period, power generation capacity will be expanded to meet increasing demand. Likewise, renewable energy technologies, especially wind power will be expanded depending on the GHG reduction requirement, as well as electricity demand increase. The scenarios in their study showed an overall increase in capacity expansion, but scenario 2 had longer construction period compared to other scenarios. GHG emission and system costs were projected to increase steadily across the explored scenarios due to energy development and GHG mitigation restriction which will require purchase of carbon credits. The uncertainty analysis reveals that although the capacity of energy technologies is projected to increase, solar power generation will not increase due to insufficient solar resources.

An Australian study by Elliston et al. (2013) examined least-cost options for supplying the NEM with 100% renewable electricity. They utilized wind, solar PV, concentrating solar thermal with storage, hydropower and biofuel gas turbines. The scenarios developed in their study maintained NEM reliability standard, which entails limited generation from hydropower to available rainfall and limited bioenergy consumption. The results show that least-cost electricity configuration was dominated by wind power, with smaller contributions from solar PV and dispatchable generators. The authors also showed that depending on the choice of discount rate, a 100% renewable system is cheaper on an annualised basis that a replacement fleet with a carbon price in the rage of $50-65 (5% discount rate) and $70-100 (10% discount rate). In a progressive study, the same authors compared their results with projected costs in 2030 of one medium-carbon and two low carbon fossil fuel scenarios for the NEM (Elliston et al., 2014). The three scenarios were based on a least-cost mix of baseload and peak load power plants, and they performed a sensitivity analysis of the results to future carbon prices, gas prices and CO_2 transportation and storage costs. Their findings identify that under a few or seemingly unlikely combination of costs can any fossil fuel scenario compete economically with 100% renewable electricity in a carbon constrained economy.

Similarly, Elliston et al. (2016) evaluated the incremental costs of higher levels of renewable energy supply using an optimisation tool to identify least cost electricity generation portfolios for the Australian NEM in 2030. The study found incremental costs to increase approximately linearly, as the share of renewables increase to 80%, afterwards it demonstrates a small degree of non-linear escalation. Also, the costs increased approximately linearly as GHG emissions cap is lowered from 150 to 30 megatonnes (Mt), while demonstrating a small degree of non-linear escalation for caps below 30 Mt.

Lu et al. (2017) modelled 90% and 100% renewable energy scenarios for the SWIS of WA. The scenarios include wind and solar PV, supplemented with a small amount of biogas and compared with a "like-for-like" fossil fuel power plant replacement scenario using a chronological dispatch model. The results indicate that 90-100% penetration by wind and solar PV are compatible with a balanced grid. When pumped hydro energy system is integrated in the model, the results culminate 90% renewable penetration, which offers low-carbon electricity at competitive prices.

Finally, Laslett et al. (2017) also modelled large scale renewable electricity system for SWIS of WA up to 2030. The scenario results show that although a balanced mix of solar PV, solar thermal, efficiency, and storage systems were the most feasible to be built on a rapid time scale. Yet it suggests that having higher levels of wind power (~80% generation) is capable of meeting SWIS reliability criteria if large amounts of distributed storage or high capacity seasonal reserve generation system such as power to gas were present.

The reviewed studies demonstrate the advancement of knowledge frontier in examining various least-cost generation options under emission reduction policies and climate change projections. However, certain research gaps were identified which can improve our understanding of the effectiveness of emission reduction policies under climate change in an optimal power system for the future. The research gaps include:

- Few studies (de Lucena et al., 2010, Schlachtberger et al., 2017, de Queiroz et al., 2019) identified least cost adaptation options under climate change and a single study (Schlott et al., 2018) examined the effectiveness of emission reduction policy under climate scenarios in the future power system. This is important for decarbonisation strategies, as least cost options involves substitution of power technologies that are vulnerable to climate change.
- The few studies (Pleßmann and Blechinger, 2017, Schlachtberger et al., 2018) that have examined the cost implication of power plant expansion under climate change or least cost electricity generation pathways, tend to not have fully considered climate impact on revenue generation . The only study identified to account for climate impact

on electricity generation revenue focused on hydropower (de Queiroz et al., 2019). Therefore, it is necessary for power companies in particular, and electricity market in general to consider changes in future revenues due to changes in future climate conditions. This will ensure proper investment planning for capacity expansion.

- Most studies examining the impact of climate change on electricity generation focus on countries with similar pattern of climate induced demand which affects power supply. Moreover, these countries usually have a uniform electricity market. This study takes a departure by examining climate impact on a country with large geographical area and complex energy market comprising two major and two minor markets operating independently.
- Most reviewed studies focus on countries located in North America, Europe, and northern Asia, which are characterised by higher winter loads and changes in solar power supply. However, just a few have concentrated on countries located in the Southern Hemisphere where most of the world's population resides, with low heating loads and seasonal variations in electricity demand.
- In comparison to Australian studies (Elliston et al., 2013, Elliston et al., 2014, Elliston et al., 2016, Blakers et al., 2017, Laslett et al., 2017), this study went further to examine the implication of CV&C on interregional electricity supply, sales revenue, generation cost, and LRMC, which can advise electricity companies on potential regions for investments and management of future energy technologies.
- Also, the cost-benefit analysis which has not been considered in previous Australian studies can assist the government in policy making, while the results of cumulative GHG emission savings and cost of avoiding GHGs can enable policymakers to identify effective emission mitigation policies.

5.3.2. Study Contributions

Given the research gaps as highlighted, this study attempts to first examine changes in future generation technologies due to the potential impact of climate change. Optimising the model to identify least-cost generation pathways under climate change and emission reduction policies such as carbon tax and RET, places this regional study for Australia among other international studies. The study contributes to body of literature by not only examining the technological implications of climate change impact on an optimised power system. It goes a step further, underscoring the economic implications which includes the social cost, sales revenue, cost of electricity production, long-run marginal cost, cost-benefit analysis, and sensitivity analysis. All in a bid to explore changes to investment, fuel and operational cost for future power generation technologies. This study takes advantage of the LEAP model's flexibility and its optimisation model – OSeMOSYS, to examine the effectiveness of emission reduction policy under climate change in an optimised future power system up to 2050. The study outcome could fill the knowledge gap between power plant expansion due to climate change impacts, and cost implication due to decarbonisation of the power sector to mitigate global warming.

5.4. Scenario and Modelling Approach

5.4.1. Scenario Approach

The main approach applied in this study follows the principle of combining exploratory scenarios with backcasting approach. The scenarios draw from chapter 4 which applied the Schwartz scenario-planning process for the Australian Energy System. The critical uncertainties identified in that study covered the energy system as shown in Figure 4.2 in chapter 4. However, the current study combines the scenario logic of the previous study, with special emphasis on electricity generation, while further applying backcasting approach.

Backcasting approach appears in some studies (Börjeson et al., 2006, Quist et al., 2011). According to Robinson (2003), backcasting approach usually possesses two main features which include their normative nature and working backwards from a particular desired future end-point. This usually requires two phases where visions into the desired future are developed in the first phase, followed by the second phase which deals with the backward analysis of how the visions can be achieved (Quist et al., 2011). Studies agree that the first phase is typical of backcasting methodology (Quist and Vergragt, 2006, Giurco et al., 2011, Svenfelt et al., 2011), while the second phase draws from the future into current times to equally exemplify backward analysis (Van de Kerkhof, 2006, Kok et al., 2011).

Just akin to backcasting, scenario planning adopts two phases. The first which is the development of progressive steps taken to address an issue from the current period to the future period, while the second is a forward analysis on how the current approach can achieve a future goal. Studies exist that have adopted scenario planning (Zhang et al., 2011, Kemausuor et al., 2015, Nojedehi et al., 2016, Zivkovic et al., 2016, Yang et al., 2017, Kim, 2018, Pastor, 2009). In Pastor (2009), three scenario planning processes with forward analysis were identified – the Kairos Future, Shell, and Schwartz scenarios. The difference between the Shell process and others lies in the organization vs individual perspective exclusive to it. Whereas, the Schwartz vs Kairos had inside-out vs outside-in perspectives respectively. All identified scenarios are exploratory in the sense that they show the implications of different strategies taken, as against merely predicting the future.

The study by Kok et al. (2011) identified the pros and cons of applying explanatory and backcasting approaches, and further recommended the combination of both in scenario analysis. Also, both approaches are deemed complementary and efficient in identifying robust strategies (Van Berkel and Verburg, 2012, van Vliet and Kok, 2015). This study therefore adopted them for the period of 2014 – 2050, given identified desired endpoints. This present study draws from some five steps that emerged from previous studies where exploratory scenarios combined with backcasting approach (see Figure 5.3). The five steps are explained in detail below.

Step 1: Selecting a desired endpoint in 2050. This study has set its desired endpoint for 2050. It hopes to achieve an efficient electricity sector, where energy is affordable, reliable, and relatively clean.

Step 2: Identifying obstacles, opportunities and milestones. On the issue of energy affordability, retail electricity prices in Australia have surged higher, and is among the highest in the world (Potter and Tillett, 2017). In the past, retail electricity prices were driven by network cost, but since 2017 became driven by wholesale electricity prices due to the increase in natural gas prices (McConnell, 2018). This further justifies the need to move away from gas to alternative energy such as renewables which are proven to be cost effective (Cunningham, 2018).

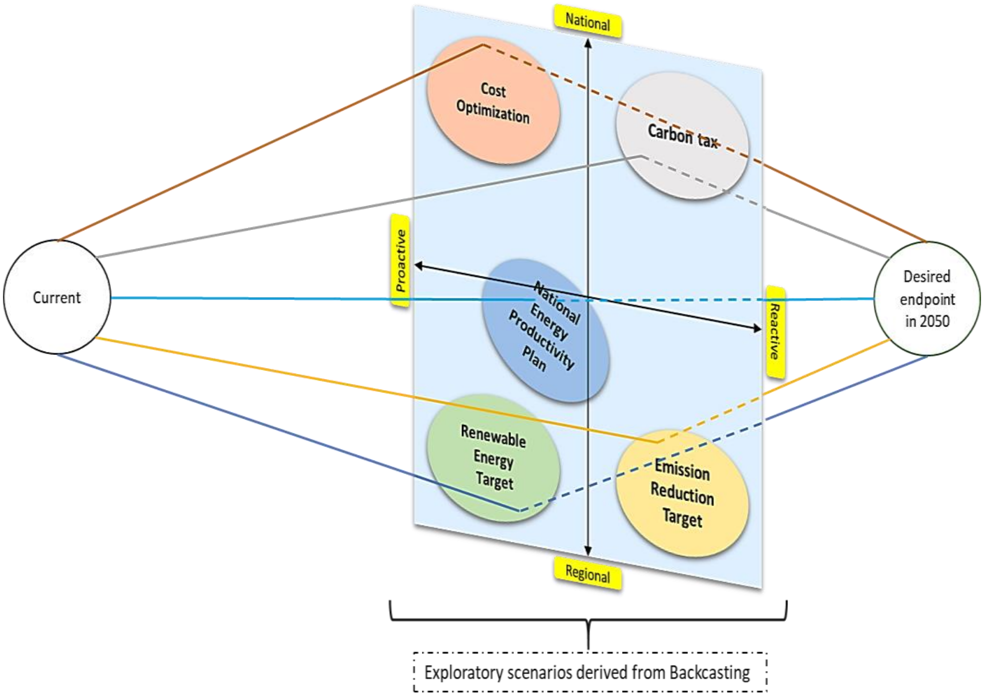

Figure 5. 3: Combining Exploratory Scenarios and Backcasting Approach.

Source: Author's modification from (van Vliet and Kok, 2015)

In terms of reliability, Australia has endured some series of blackouts in South Australia (SA) due to tornadoes in 2016 (Operator, 2017a), heatwaves and supply shortage in 2017 (Warren, 2017), and low-shedding in New South Wales (NSW) in 2017 (Operator, 2017d). Renewable sources of energy and battery storage technologies are shown in studies to be dependable (Stock et al., 2018), owing to their relative immunity to climate change disruptions (Anthony et al., 2017).

Further, compared to other developed countries, GHGs emission in Australia ranks very high, in spite of abundant renewable energy resources at the country's disposal (Cheung and Davies, 2017). Realizing this, the Australian government at a time closed down some ageing coal power plants (Energy, 2017a). This shows their readiness to move away from fossils to clean energy in the generation of power. This is observable in some envisaged policy milestones of the Australian government, as adopted by this study. They include, Renewable Energy Target, Emission Reduction Target, National Energy Productivity Plan, and two additional policies – cost optimisation and the introduction of carbon tax.

Step 3: Developing policy scenarios. The milestones, obstacles and opportunities identified in step 2 are used to develop policy scenarios in view of achieving the 2050 desired endpoint. Therefore, the milestones will serve as framework for policy scenarios in this study, with each of them aligning with milestones leading to the 2050 goal. Given application of the steps above, five policy scenarios are generated. Table 5.1 shows the scenario assumptions and policy options for the power plants as they are discussed below.

Base Case (BC) scenario continues the historical trend of low energy intensity with an average annual rate of 1.4% since the period of 1980–2013 (Stanwix et al., 2015). An updated study by the Bureau of Resources and Energy Economics (Syed, 2014) assumed the rate of end-use energy efficiency at 0.8% until 2050. This is consistent with the Treasury's suggested energy efficiency in the 2014 RET Review (Regulator, 2015c). The BC scenario power generation-expansion plan follows the Australian Energy Market Operator's (AEMO) base neutral scenario case (Operator, 2016c). In this study, the BC scenario modelling for power plan planning from 2014 – 2050 was done through LEAP's running costs. The electricity system dispatch for each year was in merit order of running costs where running costs was the sum of variable operation and maintenance (O&M) costs, as well as fuel costs.

Imports and exports of electricity around Australia helps in making the power sector more efficient. To have such level of exchange thrive, there is need to scale up capacity which makes the 2050 benchmark very vital. This will end up matching projected increase in future demands for power equitably. To get this more clearly, the Intergovernmental Panel on Climate Change (IPCC) Representative Concentration Pathways (RCP) at 4.5 and 8.5 conditions, as sourced from Business-as-Usual scenario were adopted from chapter 4.

Cost Optimisation or Base Case Optimal (BC OPT) scenario is a cost optimisation scenario which applies the optimisation functions of LEAP based on the linear programming code of OSeMOSYS. In this scenario, the dispatch choice is optimised on the premise of least cost electricity generation for the model. Unlike the BC scenario, the BC OPT scenario lacked capacity limits. It rather leveraged the AEMO base neutral scenario case (Operator, 2016c). However, the model was allowed to build power plants that offer electricity at the least cost to meet demand.

Table 5. 1: Scenario assumptions and policy options for the Power Plants.

Scenarios	Policies and Power Plants	Coal	CCGT	OCGT	Gas	Large Scale Solar PV	Wind Energy	Hydropower	Biomass Energy	Battery Storage	Rooftop Solar PV	Nuclear Energy	Supercritical Coal PC/CCS	CCGT/CCS	Geothermal Energy	Wave Energy	Solar Thermal	Others (oil etc.)
BC	No policy measures taken to influence power generation and capacity expansion limit follows AEMO's base neutral scenario																	
	Dispatch is based on merit order power plant running costs																	
BC OPT	No capacity expansion limit																	
	Dispatch is optimised based on least cost generation by the OSeMOSYS model																	
	Electricity imports can be avoided when import cost is higher than the cost of new capacity																	
	Scenario is based on a proactive approach from a national perspective																	
CO2	Emissions from power plants reduced by 26-28% by 2030 and 22% until 2050 (i.e. reduction of 158.86 – 171.08 $MtCO_2eq$ which is 440 – 452 $MtCO_2eq$ by 2030 and 343 $MtCO_2eq$ by 2050)																	
	OSeMOSYS model used for optimisation under emission constraint from 2014-2030 and 2031-2050																	
	Scenario is based on a reactive approach from a regional perspective																	
CT	Reintroduction of carbon tax at 15-18 US$/MtCO2 from 2014 – 2020, linearly increased to 30 US$/MtCO2 by 2030, and reaching 45 US$/MtCO2 by 2050																	
	Scenario is based on a reactive approach from a national perspective																	
RET	23% RET by 2020 for Australia; RET in NSW is 20% by 2020, 30% by 2030 and 100% by 2050; RET in VIC is 25% by 2020, 40% by 2025, 60% by 2030 and 100% by 2050; RET in QLD, SA, WA and NT are 50% by 2030 and 100% by 2050; RET in TAS is 100% by 2022																	
	Scenario based on a proactive approach from a regional perspective to reach 100% RET by 2050																	
NEPP	Energy intensity linearly decreases to 50% by 2050																	
	23% RET by 2020 for Australia; RET in NSW is 20% by 2020, 30% by 2030 and 100% by 2050; RET in VIC is 25% by 2020, 40% by 2025, 60% by 2030 and 100% by 2050; RET in QLD, SA, WA and NT are 50% by 2030 and 100% by 2050; RET in TAS is 100% by 2022																	
	Scenario is based on a proactive approach from a national and regional perspective																	
RCP 4.5	Annual GHG emissions peak around 2040 and decline; climate impact on space conditioning and power plants																	
RCP 8.5	Annual GHG emissions continue to rise throughout the 21st century; climate impact on space conditioning and power plants																	

Note: The shaded area represents the power plants affected by the policies presented in the table. Policies not shaded directly affects the model.

This implies that electricity imports can be avoided when the cost of importing electricity to meet shortfall in supply over the study period is higher than adding new capacity to the model (this applies to the seven states and territory of Australia). On the overall, the BC OPT scenario falls between a national proactive approach to reach the desired endpoint in 2050. The BC OPT scenario was placed as a national approach since the cost optimisation approach applies to the seven states and territory but considers resource availability, and electricity demand over the study period. It also examines the nature of power plants in the base year, which will be replaced by least cost technologies during the 2014 – 2050 period. As a proactive approach, the BC OPT scenario tends to select technologies that cost cheaper over the study period, likewise considers emission reduction.

Emission Reduction Target (CO2) scenario is based on Australia's 2030 emission reduction target (Energy, 2018a). The government aims to reduce GHG emissions to 26-28% by 2030. Australia's emissions were 611 Metric tons of carbon dioxide equivalent ($MtCO_2eq$) in 2005 (see input figure titled "AUS" in Figure 5.4).

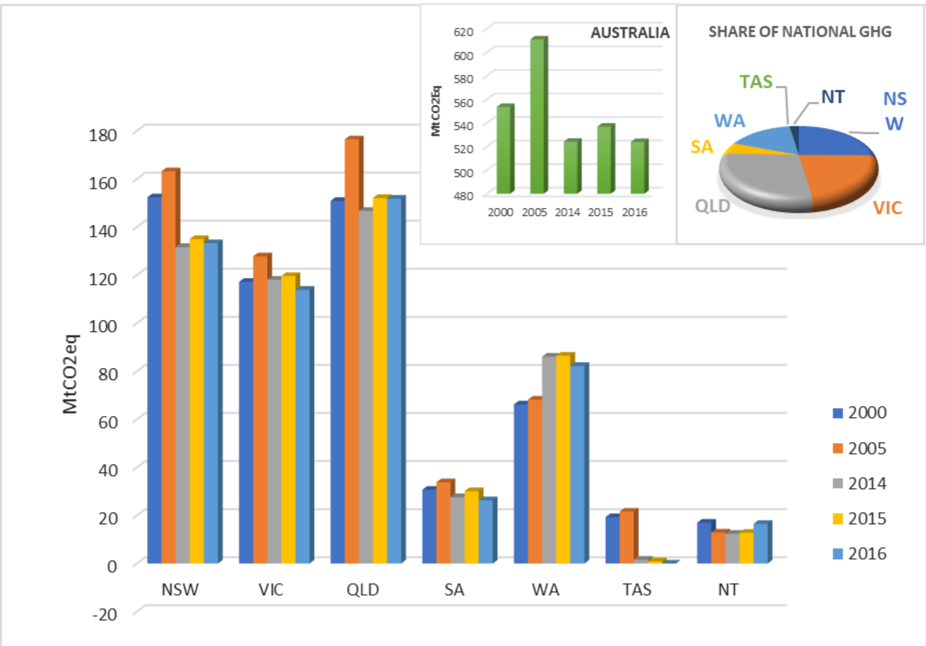

Figure 5. 4: State and Territory Total Emissions 2000, 2005, 2014 – 2016.

Note: NSW= New South Wales, VIC=Victoria, QLD=Queensland, SA=South Australia, WA=Western Australia, TAS=Tasmania, NT=Northern Territory, AUS=Australia. Source: (Energy, 2016).

At the core of meeting Australia's emission reduction target by 2030 is the Emission Reduction Fund (ERF) which aims to provide incentives for organisations and individuals who adopt practices and technologies capable of reducing their GHG emissions (Regulator, 2016). Although there are other complementary policies, this scenario is assumed driven only by the ERF. Mathematically, 26-28% reduction translates to 158.86–171.08 $MtCO_2eq$ emission reduction which gives 440 – 452 $MtCO_2eq$ emission target by 2030. The target is extended to 343 $MtCO_2eq$ by 2050, which translates to a further 22% reduction after the 2030 target has been achieved.

In the LEAP model, a CO2 cap was specified by imposing constraints and targets on annual emissions for states and territory of Australia, using each percentage contribution to national emissions as shown in Figure 5.4 (see input figure titled "Share of Nat. GHG"). The OSeMOSYS function was then allowed to optimise electricity generation under the imposed emission constraint from 2014 – 2050. In Figure 5.3, the exploratory scenario derived from backcasting places the CO2 scenario as a reactive approach from a regional perspective. This is because the scenarios assume that each state will endeavour to meet its emission reduction target at its own pace, but will collectively aim at achieving the 2030 target and sustain the gains into 2050.

Carbon Tax (CT) scenario assumes the re-introduction of the carbon tax that was repealed in 2014 (Energy, 2014). Though this time, it comes with a friendly approach to minimize costs for Australian businesses and households. The carbon price between 2012 and 2014 was 23-24 AU$/$MtCO_2$ which is 17.5-18.2 US$/$MtCO_2$[56] (Regulator, 2015b). The CT scenario hopes to reintroduce carbon tax at 15-18 US$/$MtCO_2$[57] from 2014 to 2020 for a start, then increase linearly to 30 US$/$MtCO_2$ by 2030, and reaching 45 US$/$MtCO_2$ by 2050. This is in tandem with carbon price trajectories in Guivarch and Rogelj (2017) (See Table 5.2 for details).

Figure 5.3 brings into perspective a reactive approach that entails federating units in Australia operating a uniformed carbon tax system, which would be instrumental to collectively achieving the 2050 goal. It is apparent that the essence of CT is to further reduce consumption of carbon, which is likely to affect electricity generation and cost. In order to deal with this challenge, the LEAP model aided systematic increase of the cost of

[56] Used 0.76 conversion factor.
[57] The US$ was used in this study to ensure consistence between the model parameters and data used.

selected fuels (See Table 5.2) and allowed the OSeMOSYS to optimise electricity supply considering the added carbon tax to the fuels used for electricity generation for the study period.

Table 5. 2: Carbon Tax for selected Fuels used in the Model.

Fuel Type		kg of CO2	Carbon Tax		
			2014-2020 (15-20 US$/MtCO₂)	***2021-2030(30 US$/MtCO2)***	***2031-2050(45 US$/MtCO₂)***
Natural gas/CNG (per 1000 cu. Ft)		53.12	0.13-1.06	1.59	2.39
Diesel (per gallon)		10.16	0.15-0.20	0.30	0.46
Residual fuel oil (per gallon)		11.79	0.18-0.24	0.35	0.53
Jet kerosene (per gallon)		9.57	0.14-0.19	0.29	0.43
Coal	Anthracite (per short ton)	2579	38.68-51.57	77.36	116.04
	Bituminous (per short ton)	2237	33.55-44.74	67.10	100.66
	Lignite (per short ton)	1266	18.99-25.33	37.99	56.98
Municipal Solid Waste (short ton)		2618	39.27-52.35	78.53	117.80

Renewable Energy Target (RET) scenario follows the government scheme to increase electricity generation from renewable and sustainable energy source which will reduce GHGs emission from non-renewable source. The Australian government has set a 23% RET by 2020 (Regulator, 2015c), with all states and territory equally having their respective RET target. Currently, NSW, WA and the NT are at the starting blocks, and have not made much progress in the renewable energy race based on the score-card by the Australian Climate Council (Petra Stock et al., 2017). However, the NSW Renewable Energy Action Plan aims to increase the installation of renewables over the national 20% by 2020 (Regional Development, 2016). Therefore, this study assumes that the 20% RET is achieved by 2020, increases to 30% by 2030 and reaches 100% by 2050.

Further, in 2016, the Victoria (VIC) state government set a RET of 25% by 2020 and 40% by 2025, which was supported by the *Renewable Energy (Jobs and Investment) Act 2017* (Planning, 2016). The RET scenario assumes that the target for the state of VIC was achieved, with an increase to 60% by 2030 and 100% by 2050. Likewise in Queensland (QLD), the government is committed to achieving a RET of 50% by 2030 (Young, 2015), and this study assumes that the target is achievable by 2030 and will increase to 100% by 2050. These achievements are similar to those obtainable in SA, WA, and the NT government (Parkinson, 2018, Treasury, 2017, Alan Langworthy et al., 2017).

Tasmania (TAS) is expected to record 100% RET by 2022 due to its present wide utilization of hydroelectricity (Carabott, 2017).

The study inserted RET for each state and territory into the LEAP model. This was achieved with help coming from *"Renewable Target"* function located in the *"Electricity Generation module"*, and energy technologies typical of fulfilling renewable energy obligation. The renewables identified for the renewable energy obligation is based on eligible renewable energy sources identified in the *Renewable Energy (Electricity) Act 2000* (Legislation, 2000). The RET scenario lies between a proactive approach from a regional perspective as shown in Figure 5.3. This is because each region approaches the desired 100% RET endpoint by 2050 at their own pace.

National Energy Productivity Plan (NEPP) scenario intends to follow the Council of Australian Government's Energy Council measure to improve energy productivity by 40% from 2015 to 2030 (Government, 2015). An increase in energy productivity translate to the decrease in energy intensity. In other words, energy intensity is used to measure changes in energy productivity and energy efficiency overtime (Solar Citizens, 2017). Therefore, the study assumes 40% reduction in energy intensities from electricity demand. The reduction in intensities is assumed to result from improvements in energy efficiency across buildings, equipment, and vehicles using electricity. In line with reducing electricity cost, electricity supply in the NEPP scenario was combined with the RET scenario and optimised by the OSeMOSYS for each state and territory. Energy intensity was assumed to linearly reduce to 50% by 2050. The NEPP scenario as shown in Figure 5.3 lies along a proactive approach from a national and regional perspective. This is because the effectiveness of NEPP lies with the application of RET at regional level, in as much as it is a national policy that also aims to reduce cost of retail electricity and emissions of GHGs (Council, 2017).

In lieu of the foregoing, **climate change simulation** becomes crucial. It involves the development of two IPCC climate scenarios called the **RCP 4.5** and **RCP 8.5**. The RCP scenarios are somewhat consistent with socio-economic assumptions based on possible changes in human GHGs emission. Global annual GHGs emission are assumed to peak around 2040 and decline in RCP 4.5, regardless of continual rise of emissions throughout the 21st century in RCP 8.5. This study models the RCP 4.5 and 8.5 as impacting the efficiency of thermal power plants (coal, gas, or nuclear) and renewable energy (solar or wind). This is achieved by modelling each policy scenario to simulate a climate change scenario. For example, after modelling the BC OPT scenario, the BC OPT was further simulated under the RCP 4.5 and 8.5 climate change scenarios. Therefore, after the BC OPT scenario, the BC OPT – RCP 4.5 and BC OPT – RCP 8.5 scenarios were further analysed to demonstrate the effect of emission reduction policies under climate change simulation.

Step 4. Analysing the policy scenarios: In this study, the LEAP-OSeMOSYS was adopted to analyse the policy scenario. While LEAP applies a forward analysis of the scenario, the OSeMOSYS is used for the backcasting analysis.

The LEAP is an energy system simulation model which utilizes an accounting framework for energy policy analysis of demand and supply side of the energy system (Pfenninger et al., 2014). The LEAP was developed by the Stockholm Environment Institute, and has been widely used since the late 1980s in the public and private sectors (Heaps, 2016). In this study, the LEAP was applied to determine the optimal expansion and dispatch of electricity generation power plants from 2014 to 2050. The LEAP version 2018.1.18 was applied in this study and the optimisation function was conducted through the integration of the OSeMOSYS, which is based on the GNU Linear Programming Kit (GLPK).

The OSeMOSYS computes the least cost combination of generation capacities of various electricity generation technologies and aims to meet the increasing demand at reduced constraints. The constraints can be imposed by the user, and they include, demand, plant availability, reliability, annual thermal electricity generation, maximum potential capacity, fuel and annual emissions constraints (Chatzipoulidis, 2012). The OSeMOSYS compares favourably with optimisation models such as the MARKAL/TIMES model (Howells et al., 2011). LEAP interface provides a transparent and efficient means of writing data files required for the optimisation analysis without directly interacting with the OSeMOSYS (Heaps, 2016). The LEAP-OSeMOSYS model have been used to explore alternative scenarios and their implications in Lebanon (Dagher and Ruble, 2011), Ireland (Rogan et al., 2014), Iran (Ataei and Ebadi, 2015), Tunisia (Dhakouani et al., 2017), Nigeria (Emodi et al., 2017) and Ghana (Awopone et al., 2017a).

Step 5. Evaluating the robustness of the scenarios. The ability of the scenario to meet the 2050 desired endpoint is evaluated and implications for the changes in the electricity sector will be identified.

5.4.2. Methodological Approach

The methodological approach used in this study is based on the combination of exploratory scenarios following the Schwartz methodology and a backcasting approach which has been described in section 3.1. To analyse the policy scenarios, the LEAP-OSeMOSYS model was applied with the primary objective of meeting projected electricity demand with electricity supply for the study period (2014-2050). The input data used, and their source are described in Table 5.3.

Table 5. 3: Description of the Input Data Used and Source.

Data	Source
Energy intensity for BC, BC OPT, CO2, CT and RET	Stanwix et al. (2015), Syed (2014), Regulator (2015c)
Energy intensity for NEPP scenario	Government (2015)
Power generation outlook	Operator (2016c)
Emission reduction details	Energy (2018a)
RET target details for Australia, its states and territory analysed	Regulator (2015c), Petra Stock et al. (2017), Regional Development (2016), Planning (2016), Young (2015), Parkinson (2018), Treasury (2017), Alan Langworthy et al. (2017), Carabott (2017)
Renewable energy technologies considered in RET and NEPP scenarios	Legislation (2000)
Power plant and fuel characteristics for the base year	ACC (2014), Park et al. (Park et al., 2013)
Parameters for power plant generation options (existing, committed, announced withdrawal and proposed power plants)	Operator (2018b)
Load duration curve	Operator (2018c)
Power plant emission factor	IPCC (2018a)
Transmission and distribution loss	Agency (2017)
Crude oil refineries, coal mines, coal-seam gas, natural gas, LPG resources	Australia and BREE (2014), Economist (2017), Association (2017), Statistics (2002)
Future fuel and technology cost	ACC (2014), Operator (2018a), Regulator (2018b) and Energy (2017b)

A detailed description of the electricity sector in the LEAP model used in this study[58] has been described in section 4.3.2. This includes the modification for the climate

[58] The LEAP-OSeMOSYS model used in this study and its data can be provided by sending a request to the author.

change analysis, and LRMC of electricity are provided in section 4.3.2.2 and 4.3.2.5, respectively. The approach taken for the development of the model is presented in Table 5.4. A detailed study approach and optimisation model characteristics is further described in the following subsections.

Table 5. 4: Modelling Approach.

Steps	Approach
1	Create demand branch in the current account in the LEAP model
2	Create a BC scenarios with electricity demand projection up to 2050 • Create alternative scenarios (BC OPT, CO2, CT, RET and NEPP) • In each scenario, add two scenarios named RCP 4.5 and RCP 8.5 • Model energy intensity reduction by 40% in the NEPP scenarios by 2050 using the interpolation function in the expression tab • Electricity demand and climate change induced demand are retrieved from previous study
3	Create the transformation branch in the current account in the LEAP model • Under the transformation branch, add 'Transmission and Distribution' module which includes process for electricity losses • Add another module 'Electricity Generation' under the transformation branch, which includes output fuel and processes with electricity generation technologies • Use data from Table 4.4 in chapter 4 for the base year power plant specification • In the scenarios, use parameters for electricity generation options (existing, committed, withdrawal and proposed plants), power generation outlook, and future fuel and technology cost • System load curve data are inputted in the electricity generation module as described in Figure 5.6. • Input data for planning reserve margin as shown in Figure 4.7 in chapter 4 • In the CT scenario, specific renewable energy target located under the electricity generation module. • The percentage production from Qualified energy technology should be specified in the 'Renewable Qualified' under the process sub-branch under the electricity generation module • The NEPP inherits the RET scenarios, but the electricity demand is projected to decline by 50% due to energy efficiency improvement
4	Fill in data for the primary and secondary energy resources
5	Run the model, allowing OSeMOSYS to optimise the system

5.4.2.1. Study Approach and Optimisation Model Characteristics

5.4.2.1.1. Study Approach

This study applied the optimisation features of the LEAP to obtain the optimal electricity generation expansion plan for Australia under the outlined scenarios in section 5.2.1. and Table 5.1. The OSeMOSYS integrated within the LEAP model is used for optimisation calculations to decide on the type of technology to add or retire from the electricity mix to meet a given demand for the study period. Eight input components divided into two groups are used in the LEAP-OSeMOSYS model for the Australian future electricity system as shown in Figure 5.5.

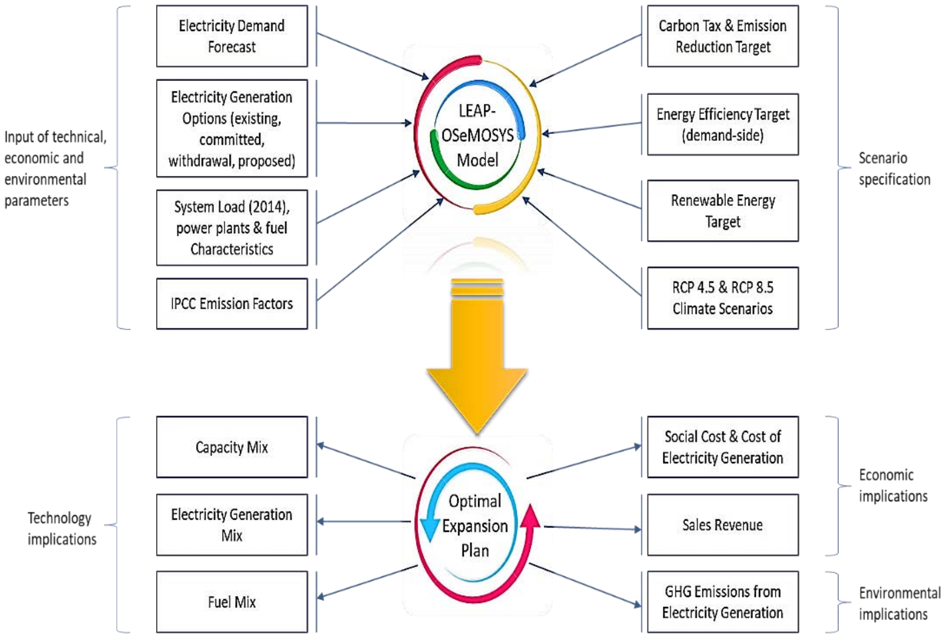

Figure 5. 5: Study Approach for the LEAP-OSeMOSYS Optimisation Analysis.

The first set of input component deals with technical, economic and environmental parameters includes data on electricity demand forecast retrieved from chapter 4. The electricity demand forecast was for the seven Australian state and territory under a base case (BC) scenario and its associated climate change conditions under the representative concentration pathways (RCP) 4.5 and 8.5 (known as BC – RCP 4.5 and BC – RCP 8.5 in this study). Parameters for electricity generation options which includes the existing, committed, announced withdrawal and proposed power plants where retrieved from the Australia Energy Market Operator's (AEMO) information page (Operator, 2018b) while generation outlook for the model was retrieved from AEMO base neutral scenario case (Operator, 2016c) for each state and territory[59].

The system load curve for each state and territory analysed in this study was retrieved from the AEMO (Operator, 2018c) and power plants and fuel characteristics were retrieved from (ACC, 2014) and (Park et al., 2013). Data for peak load shape for each region in Australia was used to develop an annual load curve of 8760 hours per year which is divided into nine blocks of 1000 hours with the last block containing 760 hours.

[59] Note that AEMO does not include expansion scenario for Western Australia and Northern Territory. However, this study linearly expanded the current stock of technologies in Western Australia and Northern Territory. Also note that the AEMO current projections for power plant expansion was up to 2036, but the base neutral scenarios were linearly extended to 2050.

The shape of the energy load curve is defined in terms of the fraction of the annual energy load in each time-slice with values sorted from high to low (Chatzipoulidis, 2012). The annual capacity load curve and energy load shape for Australian state and territory in 2014 is shown in Figure 5.6.

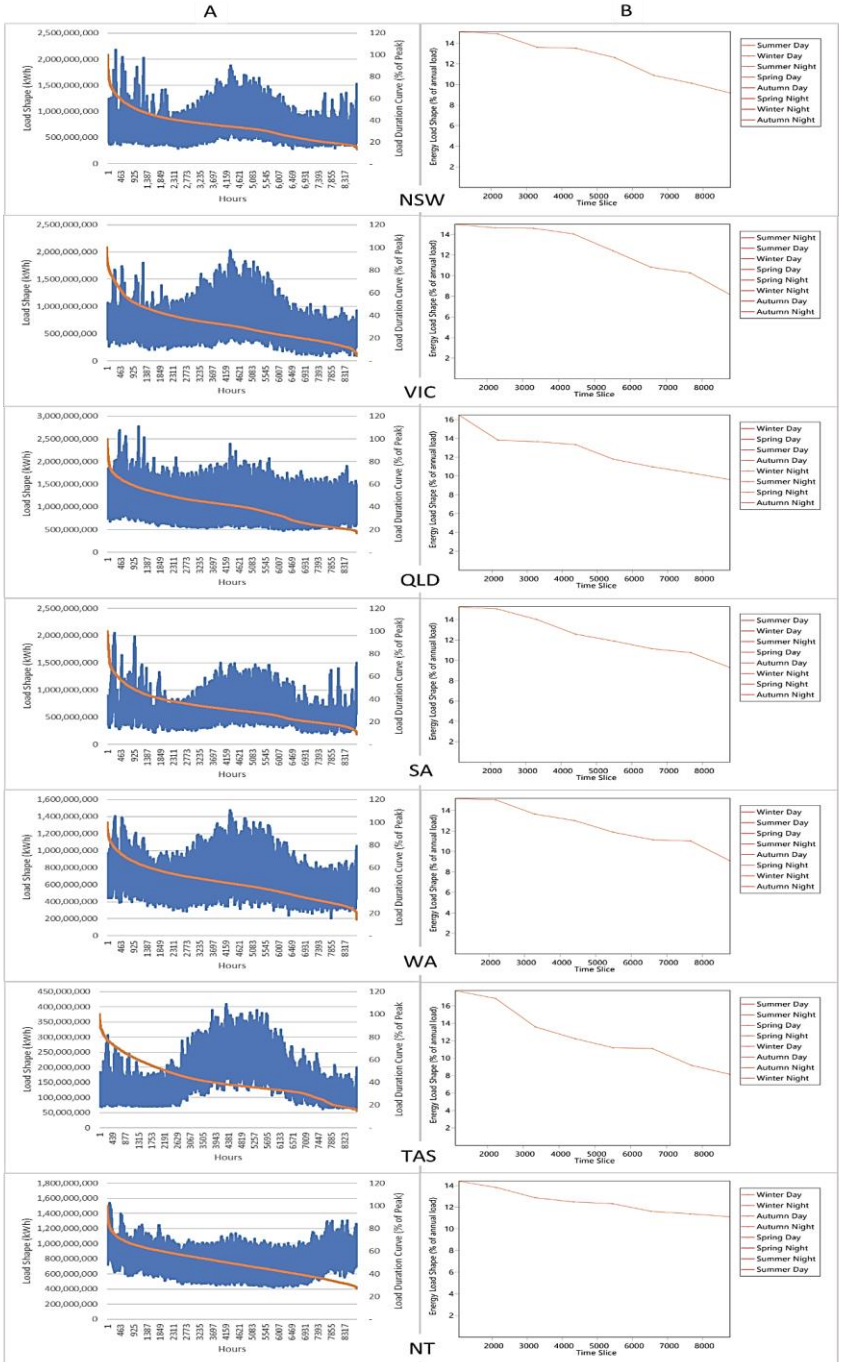

Figure 5. 6: Annual Capacity Load Curve (Panel A) and Energy Load Shape (Panel B) in 2014.

The emission factors for the power plants was derived from the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report with climate feedback (IPCC, 2018a) which are contained in the LEAP Technology and Environmental Database (TED). The second set of input deals with scenario specification which has been specified in section 5.3.1. The optimal expansion plan from the LEAP-OSeMOSYS optimisation analysis will be analysis in terms of technology, economic and environmental implications.

5.4.2.1.2. The Optimisation Model

The LEAP version 2018.1.14 (32-Bit) was used in this study and the optimisation function was conducted through the intergation of the OSeMOSYS, which is based on the GNU Linear Programming Kit (GLPK). The OSeMOSYS computes the least cost combination of generation capacities of various electricity generation technologies and aims to meet a spcified demand under various constrainits which is the model objective function. The objective fuction and constraints of the model is entered in the form of linear expressions which nust not be more than (≤), less than (≥) or be equal (=) to a given value as common in linear programming models. More specifically, the objective function of the OSeMOSYS is to estimate the lowest net present value (NPV) cost of an energy system to meets future electricity demand by minimising the total discounted cost (Howells et al., 2011). The calculation is given as follows (Augutis et al., 2015):

$$f(x) = minimise \sum_{y=1}^{Y} \Bigg(INV_{y,t,r} \times CA_{y,t,r} + FX_{y,t,r} \times C_{y,t,r} + \left[\sum_{l=0.5}^{L} \left(VC_{y,t,r,l} \times E_{y,t,r,l}^{out} \right) + FC_{y,t,r} \times FU_{y,t,r,l} \right] \Bigg) / (1 + DF)_{y=1}^{Y} \qquad Eq. (5.1)$$

Where INV is capital investment cost in US$/MW/year, FX is fixed O&M costs in US$/MW/year, VC is variable O&M costs in US$/MWh, E^{out} is total electricity generation, FC is fuel cost in US$ per litre, FU is fuel use, DF is discount factor, CA is capacity additions, C is the total capacity which includes old and new capacities, while y, t, r represents the year, technology and region respectively.

The yearly operating cost is the sum of the fixed and variable operation and maintenance (O&M) costs which is discounted back to the base year (2014) and a discount rate was applied at the beginning of the year when the technology is introduced into the model. The variable O&M costs contains two parameters which includes the rate of activity or energy outputs for each technology and unit cost associated with each power plant. The two parameters are multiplied for each time slice for the year and added to define the yearly variable O&M costs for each power plants per year. The capital investment cost for each power plant and year is the function of a per-unit capital cost multiplied by the investment of new capacity additions. The cost is discounted to the base year when a power plant was added to the model (Chatzipoulidis, 2012).

5.4.2.1.3. Constraints in the OSeMOSYS Model

As previously stated, the objective function of the optimisation model is to computes the least cost combination of generation capacities of various electricity generation technologies to meet the assigned electricity demand under constraints. The constraints are as follows (Chatzipoulidis, 2012):

- Demand constraints which specifies that E^{out} from all power plant technologies t (includes existing (CE) and proposed or candidate (CA)) cannot be less the sum of total electricity demand (ED) and transmission and distribution losses (TDL) at all time intervals (I) and years of the study period as described below:

$$\sum_{y}^{Y}\left(CE_{t,I}^{E^{out}} + CA_{t,I}^{E^{out}}\right) \geq \sum_{y}^{Y}(ED_I + TDL_I) \qquad Eq.(5.2)$$

- Power plant availability constraints which specifies that E^{out} plant technologies t cannot exceed its rated capacity (C) and the availability of I. The power plant availability factor (AF) is the amount of time a power plant can generate electricity over a certain period divided by the amount of time in the period. In other words, it accounts for the period of scheduled maintenance and unplanned outages and expressed as percentages. Also, intermittent energy sources such as renewables use capacity credit factor (CRDF) to determine its availability. This is expressed below:

$$E_{y,t,l}^{out} \leq C_t AF_t \qquad Eq.(5.3)$$

$$E_{y,t,l}^{out} = C_t \times AF_t \times CRDF_t \qquad Eq.(5.4)$$

- Reliability constraints which specifies that E^{out} capacity (existing capacity + new additional capacity optimised as C_t=$CE_t + CA_t$), of all power plants cannot exceed the sum of peak requirement (D_p) and the specified reserve margin (RM) in each year of the study period (see Eq. D.16) expressed below:

$$C_t \leq D^{Y}_{p,y,I} + RM^{Y}_{y} \qquad Eq. (5.5)$$

- Annual thermal electricity generation constraint which specifies that electricity generation from a thermal plant cannot exceed a given upper limit (cUL) associated with the plant installed capacity and availability as described below:

$$C_t^{E^{out}} \leq cUL_{y,t} \qquad Eq. (5.6)$$

- Maximum potential capacity constraint which specifies that the total installed capacity of a type power plants cannot exceed the maximum permitted capacity ($maxC$)of that plant type as expressed below:

$$CE_{y,t} \leq maxC_{y,t} \qquad Eq. (5.7)$$

- Fuel availability constraints which specifies that E^{out} from a power plant cannot exceed the maximum available quantity of fuel supply ($maxFLS$) in the power plant as described below:

$$E^{out}_{y,t,I} \leq maxFLS_t \qquad Eq. (5.8)$$

- Annual CO_2 emissions constraints which specifies annual total CO_2 emissions from E^{out} cannot exceed a specified level of CO_2 emissions (CO2) corresponding to the annual emissions reduction target. The pollutant emissions are calculated by multiplying the fuel use by emission factor (emf) assigned to the power plants.

$$\sum_{y}^{Y} E^{in}_{t,l} \times emf_t \leq CO2 \qquad Eq. (5.9)$$

5.4.2.1.4. The Integration of OSeMOSYS into the LEAP Model

The OSeMOSYS is being linked to the LEAP to allow electricity sector expansion to be optimised. The integration of the OSeMOSYS into the LEAP is shown in Figure 5.7. The LEAP provides an efficient and transparent way of optimising electricity generation using the embedded OSeMOSYS optimisation model without directly writing commands to the optimisation model. This is because a user can use the LEAP to writes data files directly into the OSeMOSYS using data such as maximum availability, process efficiency, fixed and variable O&M costs, etc from the LEAP model.

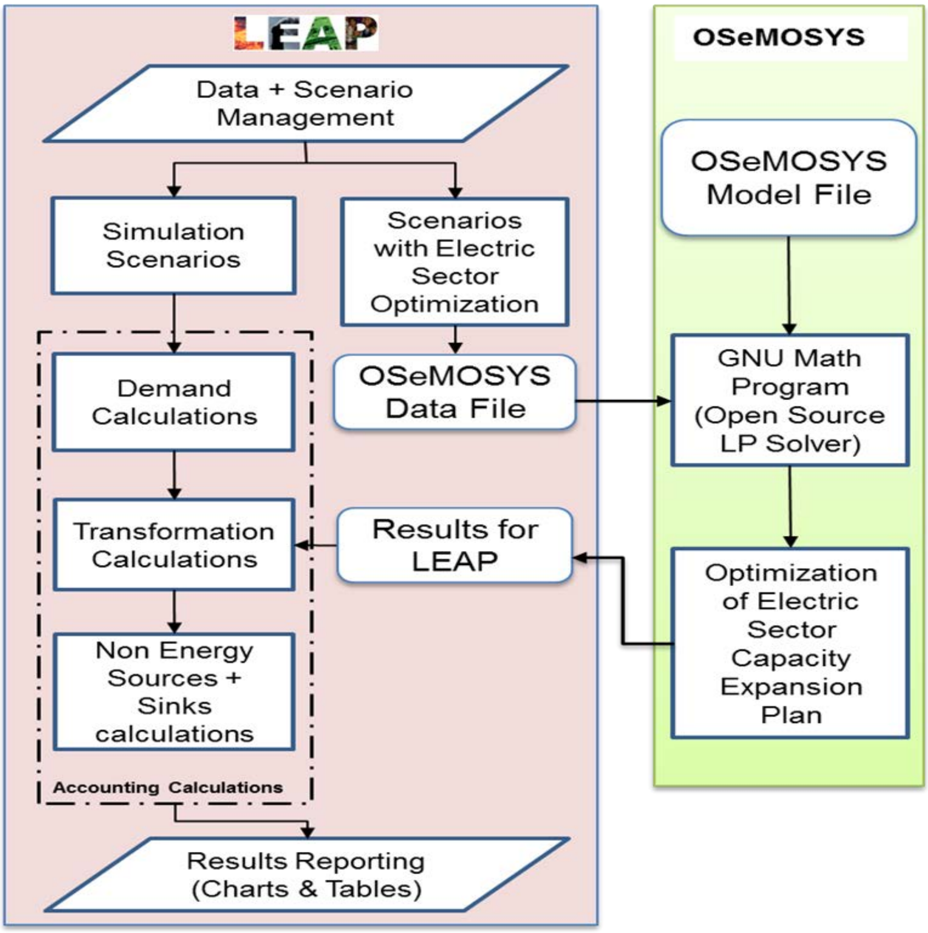

Figure 5. 7: Integration of OSeMOSYS into the LEAP.

Source: (Howells et al., 2011)

After a user inputs the required power plant data into the LEAP, the data is sent to the OSeMOSYS as a single text file (.txt) which is processed using GNUMathProg[60] which is a mathematical programming language. The GNUMathProg is supported by GNU Linear Programming Kit (GLPK)[61] which is a software toolkit that solves large-scale linear programming. The solver used in OSeMOSYS is the Ipsolve[62] which finds an optimal solution to the problem based on the variables/constraints specified and writes the

[60] See http://lpsolve.sourceforge.net/5.5/MathProg.htm
[61] See http://www.gnu.org/software/glpk/glpk.html
[62] See http://lpsolve.sourceforge.net/5.5/AMPL.htm

results into a text file (.txt) in the OSeMOSYS. Afterwards, the results in OSeMOSYS are sent back to LEAP in a special result file in comma-separated values and can be viewed in the standard results report in the LEAP model.

5.5. Results and Analysis

5.5.1. Technical Analysis

5.5.1.1. Final Electricity Demand

The final electricity demand projections for states and territory in Australia (i.e. AUS) are presented in Figure 5.8 (from Chapter 4). The projections show that Australian electricity demand will increase from 248 TWh in 2014 to 507 TWh in 2050 under non-climatic conditions with an annual growth rate of 1.7%. On a state level, NSW, WA and NT will have the highest annual growth rate 2.5%, followed by VIC, QLD, SA at 1.2%, 1.0% and 0.6%, respectively. The state of TAS is projected to have a negative annual growth in electricity demand of -0.7% with electricity declining from 13 TWh in 2014 to 10 TWh by 2050. Under RCP 4.5 climatic condition, Australia's electricity demand is projected to further increase by 3% from the BC electricity demand by additional 21 TWh, while the more sever RCP 8.5 climate scenario is projected to increase the BC forecast by 6% (i.e. additional 36 TWh) by 2050.

On the state level, climate change scenarios are projected to have the most impact in VIC, SA, and QLD with an increase average annual growth rate in electricity demand ranging from 3% - 4%. Under the BC scenario, RCP 4.5 will increase to 7% - 9% in RCP 8.5 climate conditions. The increase in electricity demand will occur due to rising demand for cooling services during the summer month in NSW, QLD, and NT, while SA and VIC is expected to have winter peak demand due to heating demand that is projected to increase before mid-century (see Chapter 3). In the BC scenario and its climate change conditions, energy efficiency was not introduced into the model because the focus of this study is on the supply side, but efficiency introduced 40% energy productivity improvement in the NEPP scenario which will be later seen.

The foregoing emphasizes that consumers' consumption behaviour and economic status, alongside changes in climate across varying geographical locations (See Figure

5.6) in Australia, will determine electricity demand curve. AEMO has recommended energy efficiency and renewable technologies as the best option to match potential increase in consumption of electricity, as well as stabilize the cost of purchase, which will in-turn improve the Australian economy (Operator, 2016a).

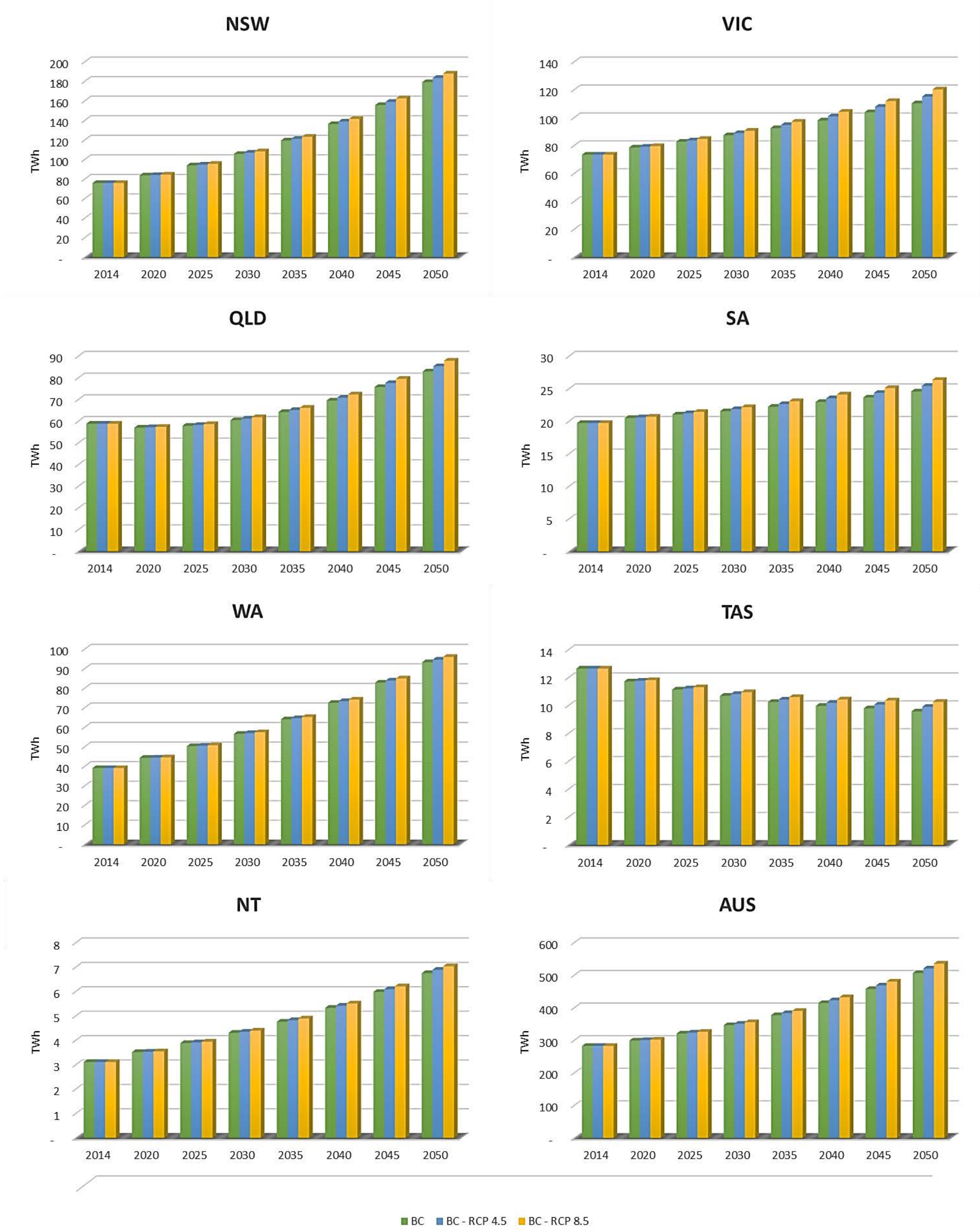

Figure 5. 8: Electricity Demand Projections.

5.5.1.2. Installed Capacity

The electricity generation installed capacities are shown in Figure 5.9 for the BC, BC OPT, CO2 and CT scenarios in the first column and the scenarios share same capacity expansion plan for the study period. The RET in the middle column and NEPP in the last column are observed to have an elevated integration of renewable energy technologies. However, 40% decrease in NEPP scenario due to increased energy productivity leads to reduction in electricity demand which implies lower capacity requirement for electricity generation. Therefore, capacity expansion in the NEPP scenario for NSW, VIC and WA is 9 GW, 1 GW, and 4 GW respectively, lower than the RET scenario which was higher than BC, BC OPT, CO2 and CT scenarios by 12 GW in NSW, 1 GW in VIC and 6 GW in WA. The reason for increase generation capacity for RET scenario is due to: (i) the decrease in the capital costs of renewable energy technologies during the study period, and (ii) the low capacity credits of renewable energy in the electricity generation mix, which leads to lower power output than fossil fuel technologies (McPherson and Karney, 2014, ClimateWorks, 2014, Awopone et al., 2017b).

From Figure 5.9, it is observable that the capacity of coal power plants is retired before 2050 across Australian states, except for QLD, VIC and NSW, where 6 GW, 2 GW and 1 GW is left by the end of the study period. The share of gas power plants such as open cycle gas turbine (OCGT) and combined cycle gas turbine (CCGT) are increased, except in SA, TAS and NT where capacity expansion is kept at minimal level. Nuclear, carbon capture and storage (CCS) enhanced supercritical coal, and CCGT power plants are also introduced into the electricity mix to allow their usage in the BC OPT, CT and CO2 scenarios. The purpose is to achieve emission reduction obligations.

However, the competition between renewables and CCS technologies was expected to constrain the introduction of nuclear power plants in the energy mix, but supercritical coal was observed to be constrained to 1 GW in NSW and VIC, 2 GW in SA and WA. The LEAP-OSeMOSYS model had not constrain the expansion of nuclear, renewables or CCS fitted CCGT, as well as supercritical coal power plants in QLD. This is in contrast to ClimateWorks (2014) study where CCS technologies were competitive with renewables, and nuclear power plants reduced the adoption of higher-capacity renewables and CCS technologies.

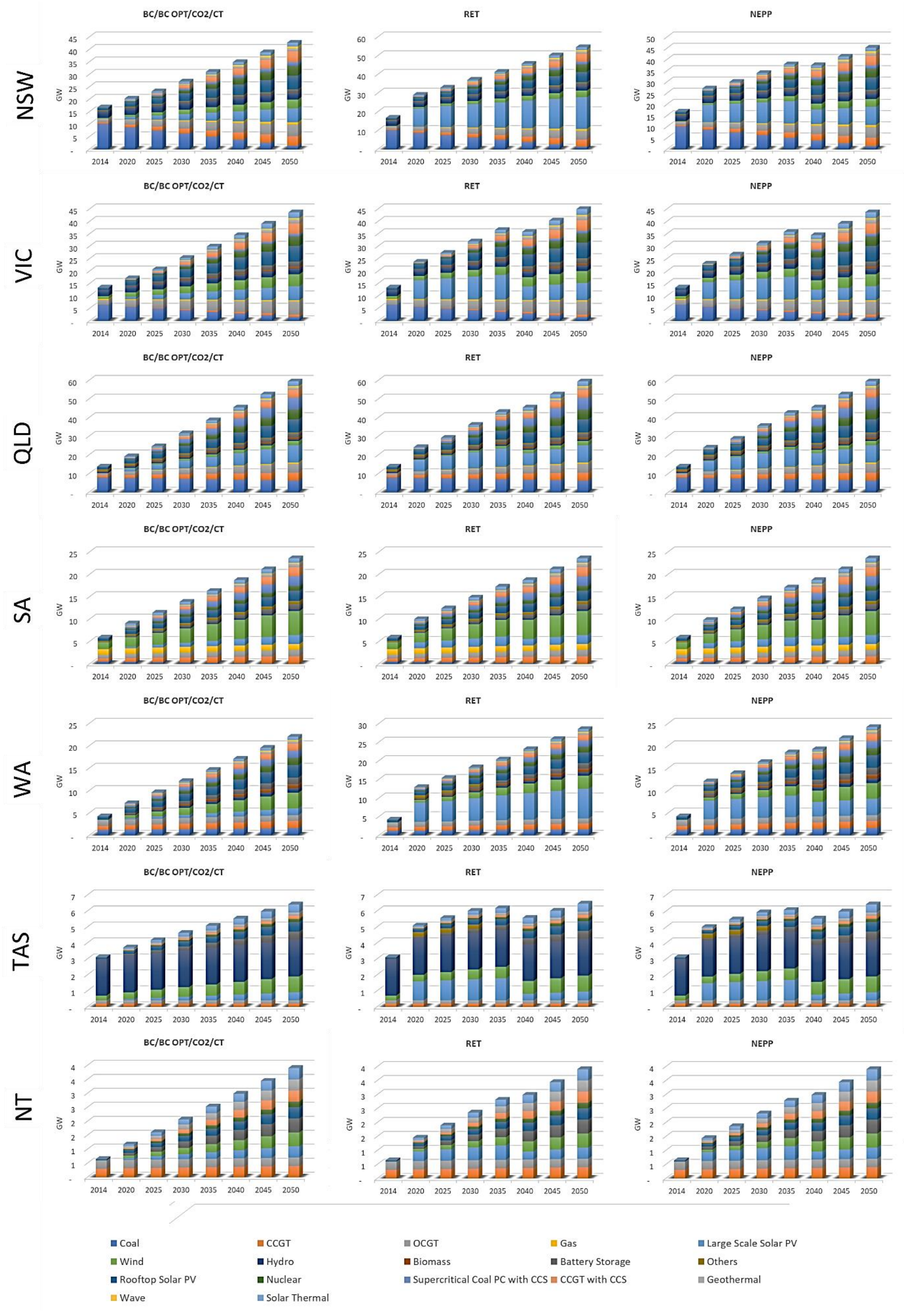

Figure 5. 9: Electricity Generation Installed Capacity.

It is important to note that nuclear energy introduction into the Australian energy system may face some current challenges due to the legislative prohibition restricting licensing and operation of nuclear power reactors (Stewart, 2017). In as much as this study assume the prohibition will be relaxed during our study period. On renewables, solar PV (large scale and rooftop) and wind (offshore and onshore) technology were identified to be installed in capacity larger than 5 GW in NSW, VIC and QLD, while wind installed capacity exceeded 5 GW in SA and WA by 2050. Large scale battery storage was also included in the model and varied between 1 GW – 2 GW across the states and territory.

5.5.1.3. Electricity Generation

Electricity generation for the seven states and territory are presented from Figure 5.10 to Figure 5.15 for the six scenarios. The results of the scenarios are shown in the first columns, while the middle and last columns are the associated RCP 4.5 and RCP 8.5 climate change scenarios. The results are presented as follows.

5.5.1.3.1. Base Case and Base Case Optimal Scenarios

The BC scenario as shown in Figure 5.10 presents a future scenario, where the current power generation extends to the future without significant policy options to reduce fossil fuel emissions. The LEAP model in using scenario approach predicts that electricity generation will likely increase from 80 TWh in 2014 to 189 TWh in NSW, where output from coal power plants declines by 33 TWh between 2020–2050. This is replaced by supercritical coal PC (pulverised coal) with CCS which was endogenously increased by LEAP from 2019 to 2050 to about 11 TWh.

Output from renewables such as wind comes to the fore by 2030 at 1 TWh which would gain slight increase to 2 TWh. Other renewables such as geothermal, wave, solar and biomass have relatively lower power output not more than 4 TWh, but power generation for fossil fuel increased to 131 TWh consisting of gas and nuclear power plants. Under climatic conditions, a distinctive change is observed as energy generation from renewables increases by 87 TWh out of 193 TWh in BC-RCP 4.5, and 92 TWh in BC-RCP 8.5 conditions.

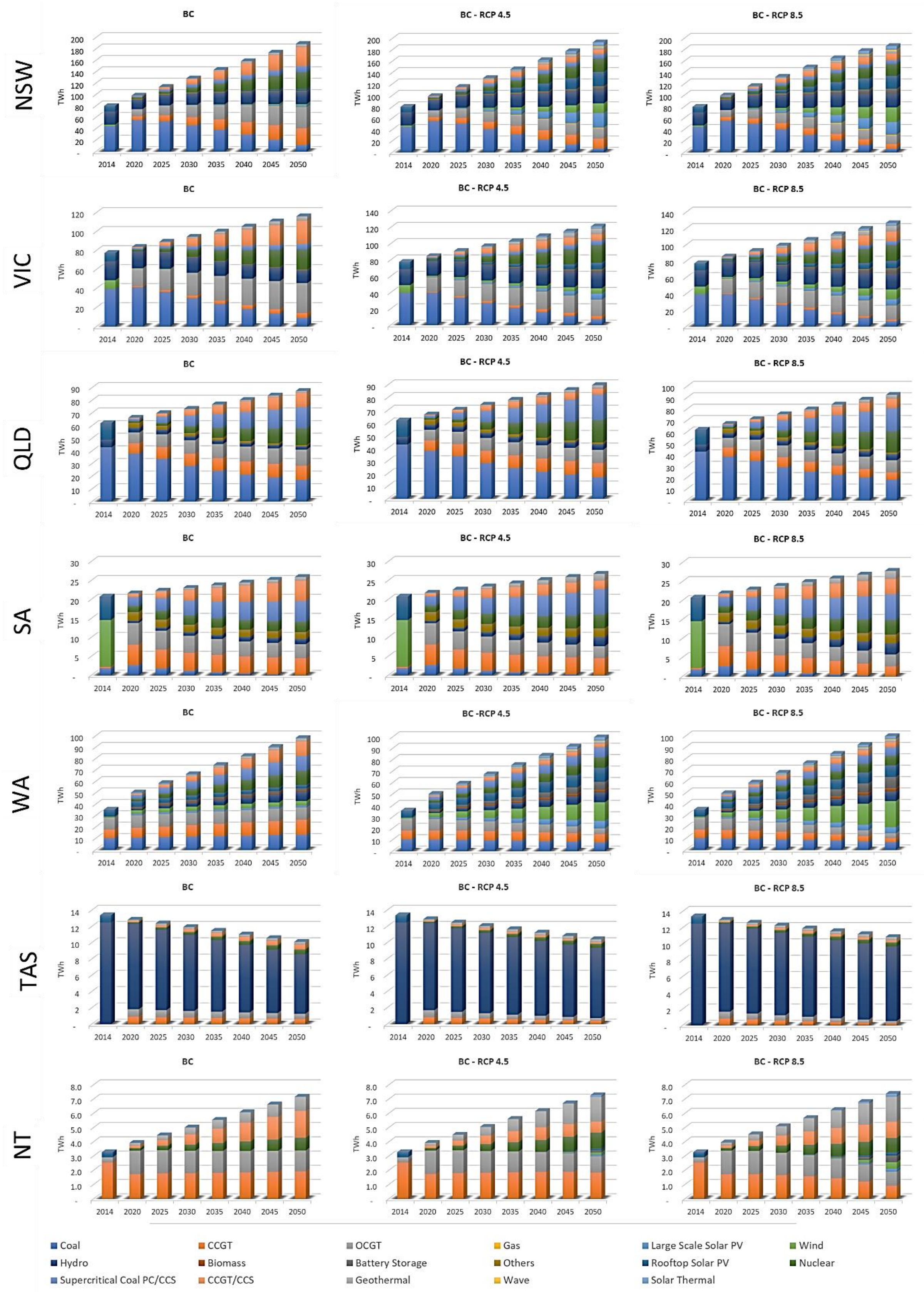

Figure 5. 10: Electricity Generation under Base Case Scenario.

The reason for this was due to the reduction in the efficiency and availability of thermal power plants which reduced power outputs, equally affecting most renewable energy sources. Under the BC scenario, VIC, BC-RCP 4.5 and 8.5 climate change conditions led to increased generation of renewables such as wind, solar, geothermal and battery storage technology. This could triple by 9 TWh in BC-RCP 8.5 to account for the low power output from fossil fuel power plants due to rising temperatures.

In QLD, the electricity grid is fossil fuel dominated in the BC scenario and climate change conditions did not force a significant increase in renewable generation. The QLD case was similar to SA where BC-RCP 4.5 and BC-RCP 8.5 scenarios had 1 TWh and 2 TWh differences to the BC scenario, respectively. The BC OPT scenario (see Figure 5.11) is based on the LEAP cost optimisation features relevant to OSeMOSYS which aims to generate electricity to meet a specified demand at the least cost. The results for the BC OPT without climate change show the expansion of renewable energy generation to about 90 - 95% in NSW and WA, while other states had 100% renewable energy generation.

When rising temperature is introduced into the model, fossil fuel power plants were introduced in NSW and WA to meet the increase in weather related demand, while output from renewables was increased in other states to meet the demand at the least cost of electricity generation. These variations owe to the cost of operating the power plants, as well as fuel cost which differs across the states in Australia. Therefore, the OSeMOSYS optimisation model builds on this foundation, so as to increase power generation from sources that meet both weather and non-weather-related demand.

One factor predicted to clamp on electricity generation from renewables is observed regional differences in resource availability, cost of power plants operations and fuel. Thereby creating dependence on fossil fuel plants for electricity generation. However, cost-optimisation (i.e. BC OPT) scenario took proactive steps toward the 2050 desired endpoint (see figure 3). It can be seen that in NSW and WA, the model delayed the introduction of CCGT and supercritical coal plants with CCS technologies as coal power plants were gradually retired by 2030. On the overall, competition between non-renewable and renewable sources of energy was gradually ebbed in favour of the latter.

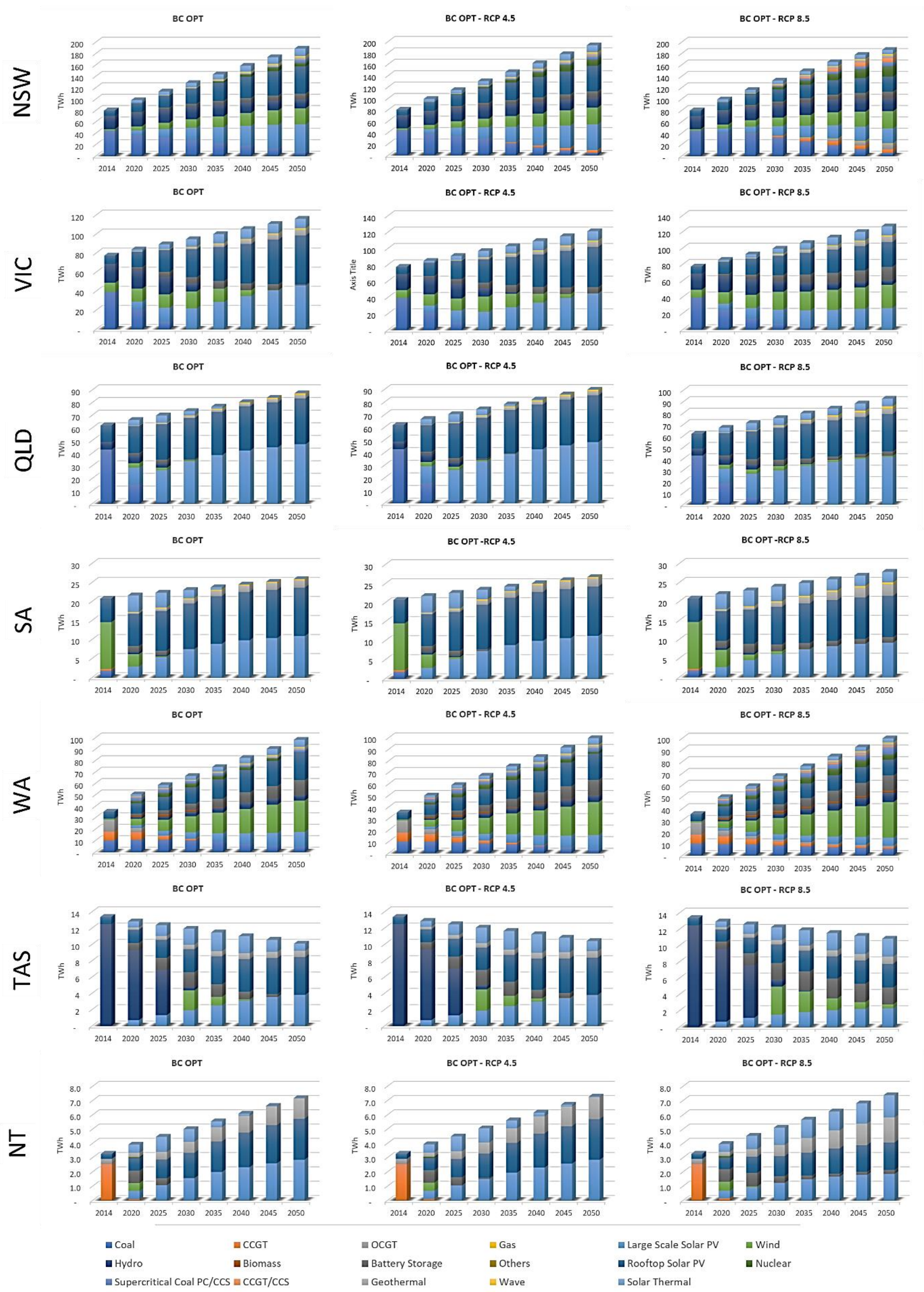

Figure 5. 11: Electricity Generation under Base Case Optimal Scenario.

5.5.1.3.2. Emission Reduction Target and Carbon Tax Scenarios

The introduction of emission reduction target will impact adoption of low carbon technologies. Figure 5.12 shows the optimal generation pathway for the Australian energy system under CO2 constraints. Introduced targets led to higher deployment of nuclear and gas power plants, with CCGT with CCS technologies not left out. More so, conventional and supercritical coal PC plants with CCS had lower power outputs compared to nuclear and gas plants. Renewable electricity was observed to be constrained across the states and territory, except in WA were wind generation increased to 16 TWh which surpass large scale solar (7 TWh) and a little over outputs from rooftop solar PV (13 TWh).

However, CO2 with climate change scenarios leads to the increased production of electricity from renewable energy source. For example, the CO2 – RCP 4.5 conditions for NSW increased solar electricity by 57 TWh (large scale 51% and rooftop 49%) and wind by 19 TWh by 2050. The much sever climate change conditions (i.e. CO2 – RCP 8.5) further increased output from wind source by 27 TWh, while large scale and rooftop solar had a combined 46 TWh, which is a reduction of 11 TWh. Such reduction is traced to low efficiency in power output due to temperature increase. The same situation was observed in VIC and NT, while renewable electricity was not available in QLD and SA under a CO2 scenario.

The CT scenario explored the effect of re-introducing carbon tax in the Australian energy system. In the model, carbon tax policy was introduced as a constraint on the optimal generation system which is optimised by OSeMOSYS function as built in the LEAP model. The results of CT scenario are presented in Figure 5.13 and show that hydropower generation and thermal power decreases as carbon tax increase across the study period. In fact, fossil fuel which was dominant across the electricity mix of states and territory in Australia was observed to decline by 49% while renewable was 51% in NSW; VIC had 40% and 60%; SA had 44% and 56%; TAS had 12% and 88%; and NT had 34% and 66% for fossil fuel and renewables, respectively. However, the CT scenario led to an increase in fossil fuel in the state of QLD and WA by 54% and 78% against renewables at 46% and 22% for the two states, respectively.

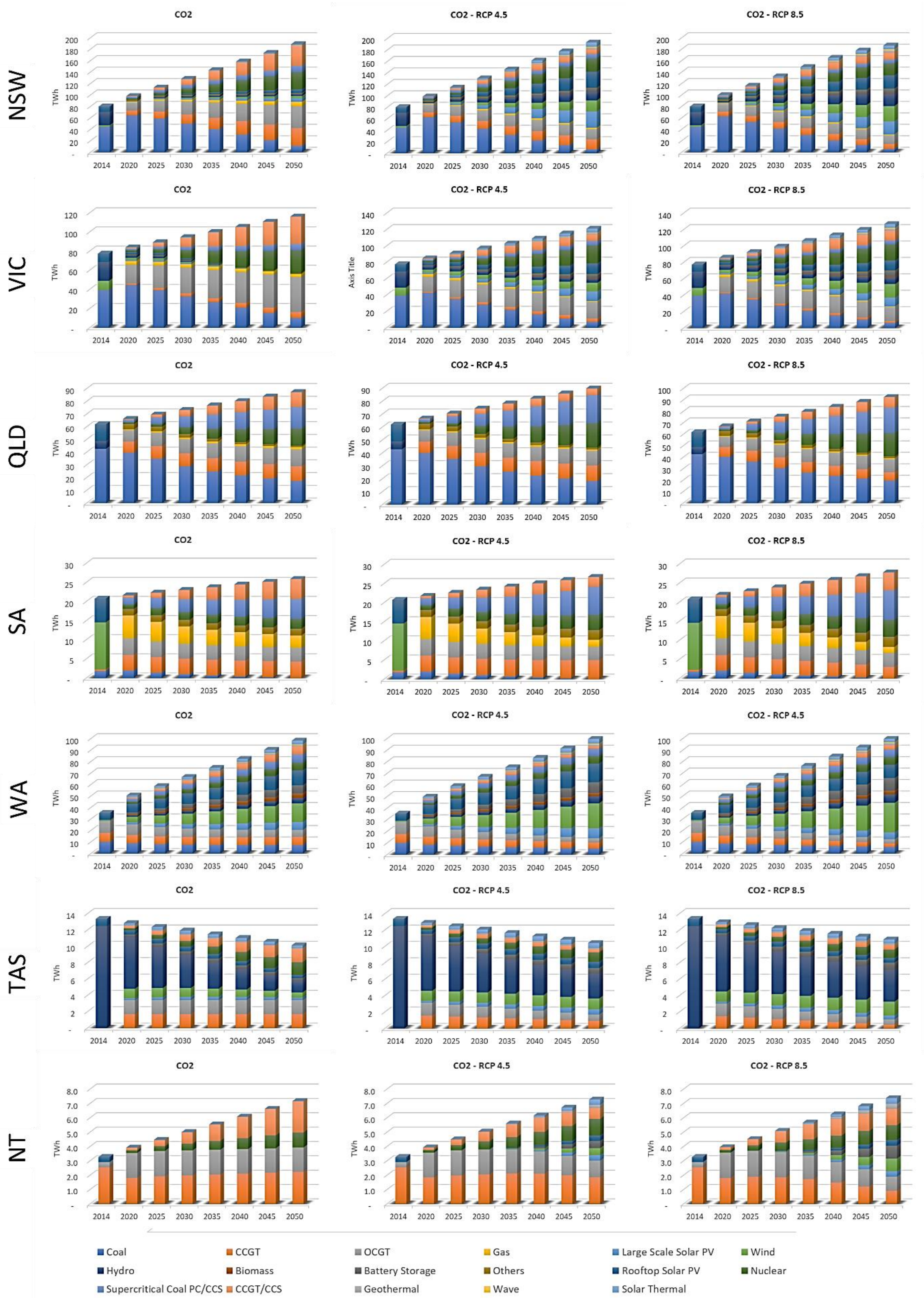

Figure 5. 12: Electricity Generation under CO2 Limit Scenario.

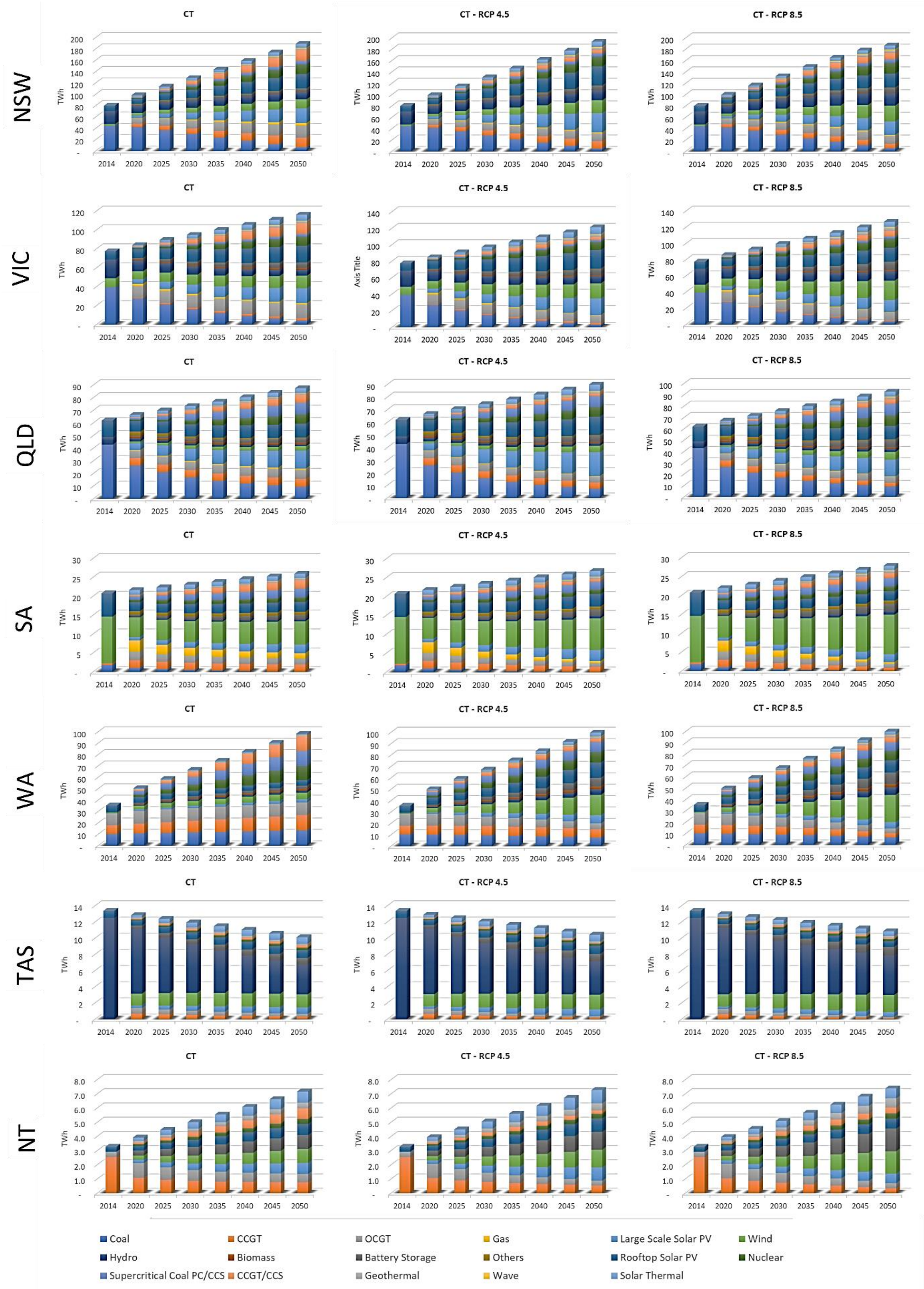

Figure 5. 13: Electricity Generation under Carbon Tax Scenario.

The implication is, the introduction of carbon tax will most likely increase electricity generation across Australia, except in the state of QLD and WA. This might be attributed to preponderance of fossil fuel resources in the two states as compared to other Australian states and territory (Australia, 2018b). A look at the climate change scenarios reveals that CT – RCP 4.5 conditions doubles the electricity output from renewables, compared to CO2 and its associated climate change scenarios. More specifically, the state of QLD, SA and NT with lower renewable electricity generation in the CO2 scenario had higher renewable output, but wave energy appear to be missing in the electricity generation mix in TAS and NT.

This may be due to the relative cost of wave technology and availability, compared to other renewables. The results show that the introduction of carbon tax will have more influence in boosting electricity supply from renewable energy technologies, thereby reducing the amount of fuel required for power generation. This is because, carbon tax will mainly affect the cost of electricity production in thermal power plants and make renewables in high demand. This implies that introducing carbon tax will tend to exercise more positive impact on Australia's energy security, compared to the current emissions reduction target.

5.5.1.3.3. Renewable Energy Target and National Energy Productivity Plan Scenarios

The RET scenario examines a state-wide adoption of renewable energy target as a proactive step in mitigating climate change. The results as presented in Figure 5.14 shows that fossil fuel power plants are retired before 2020, and the share of renewables such as solar PV systems are increased to account for 100% of electricity outputs by 2050. Support of largescale battery storage system would be of enormous importance. Electricity production hydropower were observed to be offline before 2030 in NSW, VIC and WA, while QLD and SA had electricity from hydro decline before 2025. Other renewables such as geothermal and solar thermal had higher generation in NSW, VIC and QLD with output ranging from 5 to 7 TWh. Under the RET – RCP 8.5 scenario, output from battery storage occurred from 2020 to 2025 and 2040 to 2050 in QLD and TAS, 2040 to 2050 in SA and NT, and from 2020 to 2050 in NSW, VIC and WA.

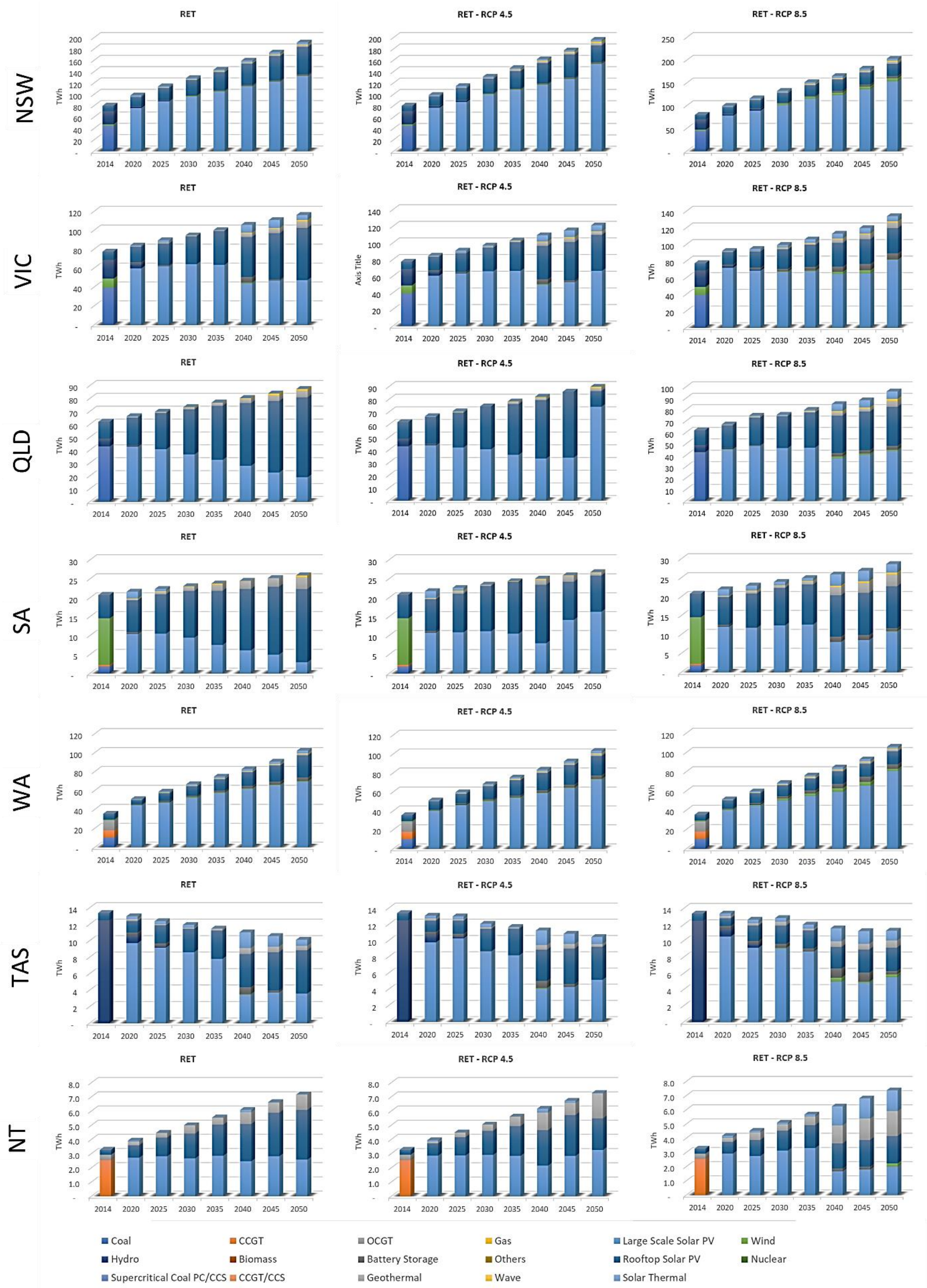

Figure 5. 14: Electricity Generation under Renewable Energy Target Scenario.

The reason for the differences in electricity dispatch across the states, territory, and study period, is due to differences in power availability as production is affected by changes in climatic conditions on one hand, and the seasonal demand affected by weather variations. Therefore, outputs from renewable sources would likely increase when additional electricity is required by the model. Similarly, the NEPP scenario which aims to boost energy efficiency, surprisingly results in reduced power output. The results (see Figure 5.15) show that compared to the RET scenario, renewable electricity which makes up 100% of total power output will be 78 TWh, 46 TWh, 35 TWh, 10 TWh, 43 TWh, 4 TWh, and 3 TWh less in NSW, VIC, QLD, SA, WA, TAS and NT, respectively by 2050.

It can be observed that the two associated climate change conditions for NEPP had little effect in forcing additional renewable energy technologies into the electricity mix across the states and territory. The results from RET implies that the effective implementation of renewable energy target in the seven Australian states and territory will be effective in replacing thermal power plants as early as 2023. Whilst large-scale battery storage will have an effective role in an exclusive renewable future, though with the support of solar thermal system. Further, NEPP seeks to add to state-wide renewable energy target, with tendencies of reducing the need for additional renewable energy production, which lowers capacity requirement for electricity generation from renewables.

Thus, our results is in partial agreement with (Lu et al., 2017) where 90% renewable energy generation is possible in the SWIS of WA with wind, solar and pumped hydro energy storage. Also, 100% renewable electricity was possible in the study with PHES only (Lu et al., 2017). Similarly, Laslett et al. (2017) found a balance mix of solar PV, solar thermal, energy efficiency and storage as the most feasible mix to achieve 100% renewable electricity for the SWIS of WA. Another study suggests that wind and solar will dominate the Australian electricity grid in the future and showed that the technologies can deliver a 100% renewable electricity to the NEM (Blakers et al., 2017). This is a similar outcome to the RET scenario developed in our study, which is based on a 100% renewable electricity. However, this study applied a least cost modelling approach which differs from the “like-for-like” fossil fuel replacement applied in previous studies.

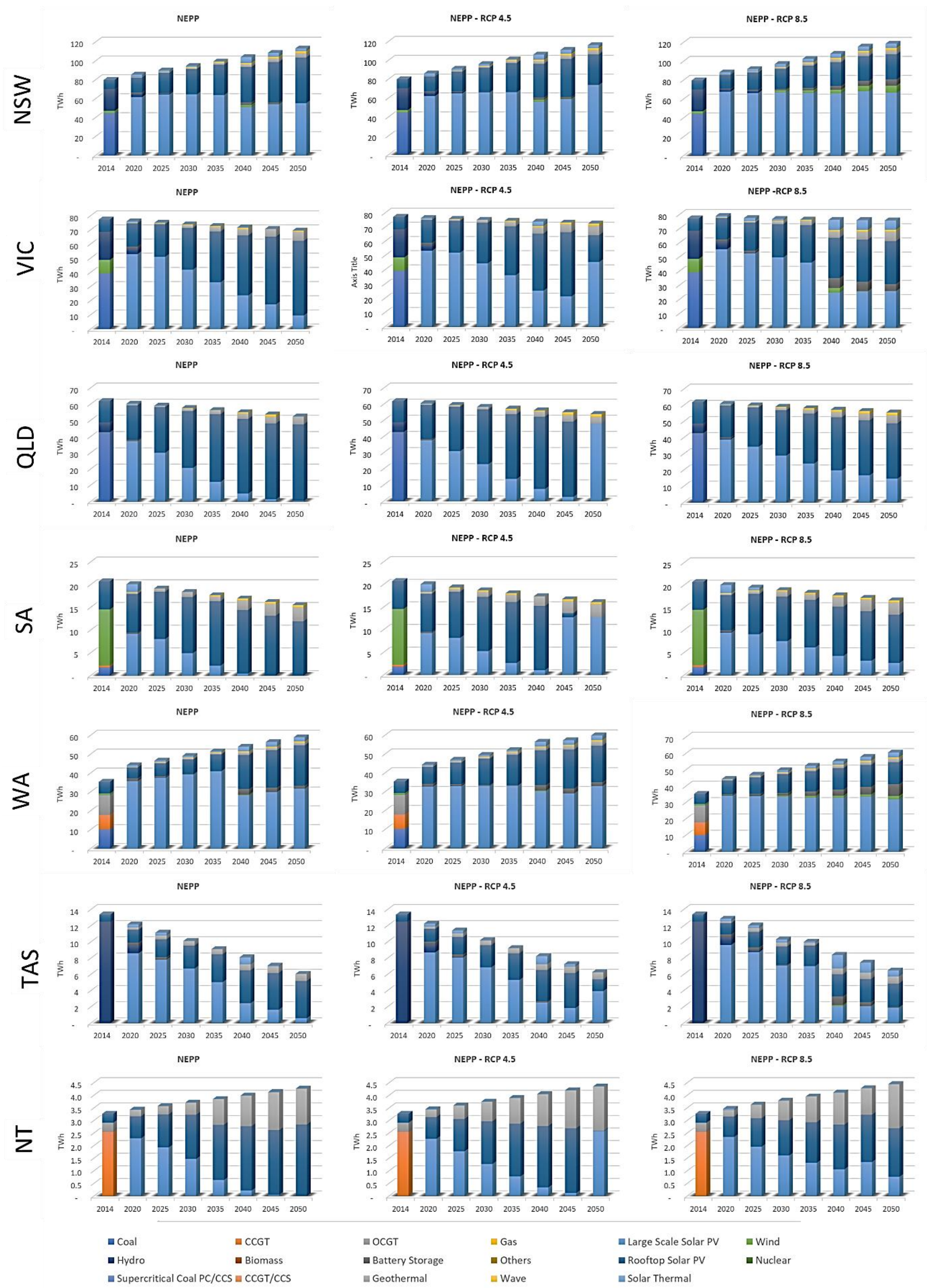

Figure 5. 15: Electricity Generation under National Energy Productivity Plan.

5.5.1.3.4. Fuel Mix and Technology Switching

The fuel mix for the Australian electricity sector is shown in Figure 5.16 which reveals changes in the fuel mix for the six policy scenarios.

Figure 5. 16: Electricity Generation Fuel Mix.

From Figure 5.16, the Australian (AUS) electricity fuel mix was dominated by coal (47%) and hydro (21%) in 2014. The fuel mix is projected to change under BC scenario in 2030, when the share of natural gas increases by 37%, followed by coal at 36%, and hydro decreasing by 13%. By 2050, the BC scenario predicts natural gas to have the highest share (48%) of fuel for electricity generation.

Under BC OPT scenario, the fuel mix mainly consists of solar and wind energy from 2030 – 2050. The CO2 scenario shows that natural gas is the main source of electricity in the fuel mix, followed by coal. In 2030, the CT scenario shows that solar and natural gas are the main electricity source, and this is likely to survive into 2050. In the RET and NEPP scenarios, solar energy was the dominant fuel source in the electricity mix, followed by wind energy. The results are similar on the state-level, except for TAS where hydro will continue to dominate the fuel mix, but appears facing competition in RET and NEPP scenarios from geothermal and solar energy sources.

The results for technology switching (see Figure 5.17) shows the effect of changing the technology mix. The results show that policy and associated climate change conditions are compared to BC scenario. For Australia, results equally show that climate change leads to increased technology substitution with 178 TWh of renewables (including hydro) replacing 162 TWh of fossil fuel power plant generation by 2050, under the BC – RCP 8.5. In the BC OPT, CO2 and CT scenarios, the technologies switching during policy simulation tend to balance the technologies introduced into the mix. This implies that no capacity was added or retired in the technology mix when compared to the BC scenario. Renewable technologies replaced non-renewables in the BC OPT and CT scenarios. Also, the capacity of renewables was increased under the two climate change conditions for each policy scenario.

In addition, RET and NEPP show that by 2050, additional capacity for renewable energy technologies will reach 6 TWh to account for technology switching with fossil fuel plants in the BC scenario. This capacity for renewables increases to 34.9 TWh in the RET – RCP 8.5 scenario to account for shortage in electricity generation capacity due to the low capacity credit of renewable energy technologies. The most savings in capacity expansion when compared to the BC scenario was identified in the NEPP scenario. Here, savings in electricity generated was about 213 TWh, 219 TWh and 212 TWh in the NEPP, NEPP – RCP 4.5 and NEPP – RCP 8.5 scenarios, respectively.

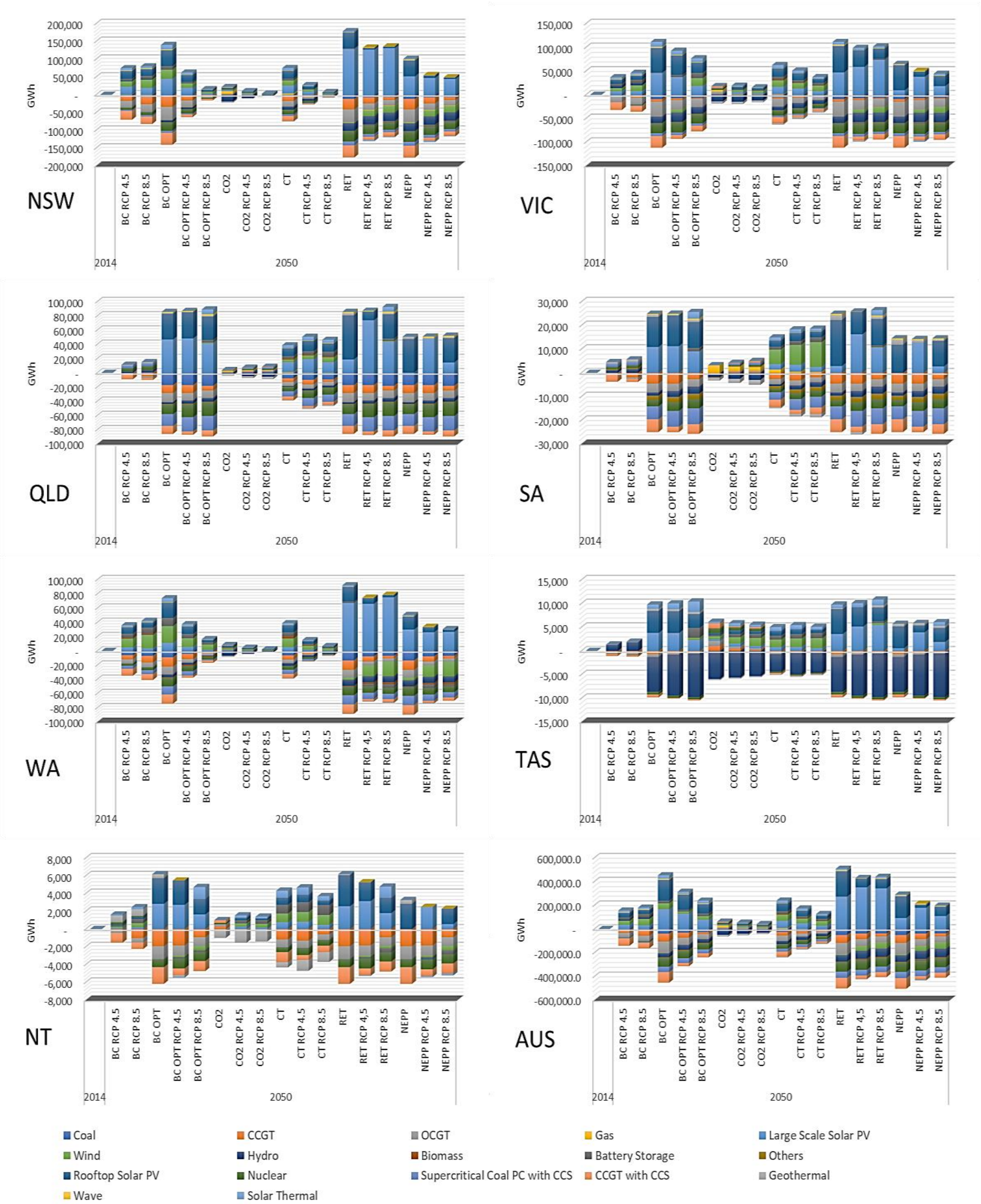

Figure 5. 17: Technology Switching for the Australian Electricity Generation Mix.

The results imply that if Australia goes through the IPCC RCP 4.5 and RCP 8.5 climate change pathways, additional capacity of 14 TWh and 17 TWh will be required, compared to the BC scenario by 2050. Further, the BC OPT, CO_2 and CT scenarios technology switching show that no additional capacity will be required or retried if their policies are implemented. However, additional capacity will be required to meet the demand under RET dominated by renewable energy technologies. This leaves the NEPP scenario as the most viable policy option that will present higher savings in electricity production when combined with RET policies for the seven states and territory in Australia.

5.5.2. Economic Analysis

5.5.2.1. Social Cost

The social cost represents the overall costs of electricity production which includes, capital, O&M costs, fuel cost, and environmental externalities. The results are presented in Figure 5.18 which are discounted to 2014 with implications for technologies. From Figure 5.18, social cost was observed to be higher in CO2 scenario across the states, followed by BC scenario, while BC OPT, RET and NEPP possess the lowest social cost. This shows the cost competitiveness of scenarios, especially with high integration of renewable energy in the electricity mix. The share of social cost by each power plants (see panel B in Figure 5.18) show that nuclear, coal and gas power plants (including those with CCS), had higher share of social cost. They were followed by hydropower in NSW, VIC, QLD and TAS.

Renewable energy technologies had lower social cost which is due to the absence of environmental externality, and anticipated reduction in the future cost of renewables before 2050. Our results agree with the social cost results from Kim (2018) on the South Korean electricity sector. Another contributing factor to the decline in social cost is the fuel cost which places electricity production from fossil fuel power plants in the BC and CO2 scenarios higher than the BC OPT, RET and NEPP scenario. In the CT scenario, the results for the seven states and territory show that the social cost will decrease to US$ 1,168 million in 2050 which is US$460 million lower than the BC scenario.

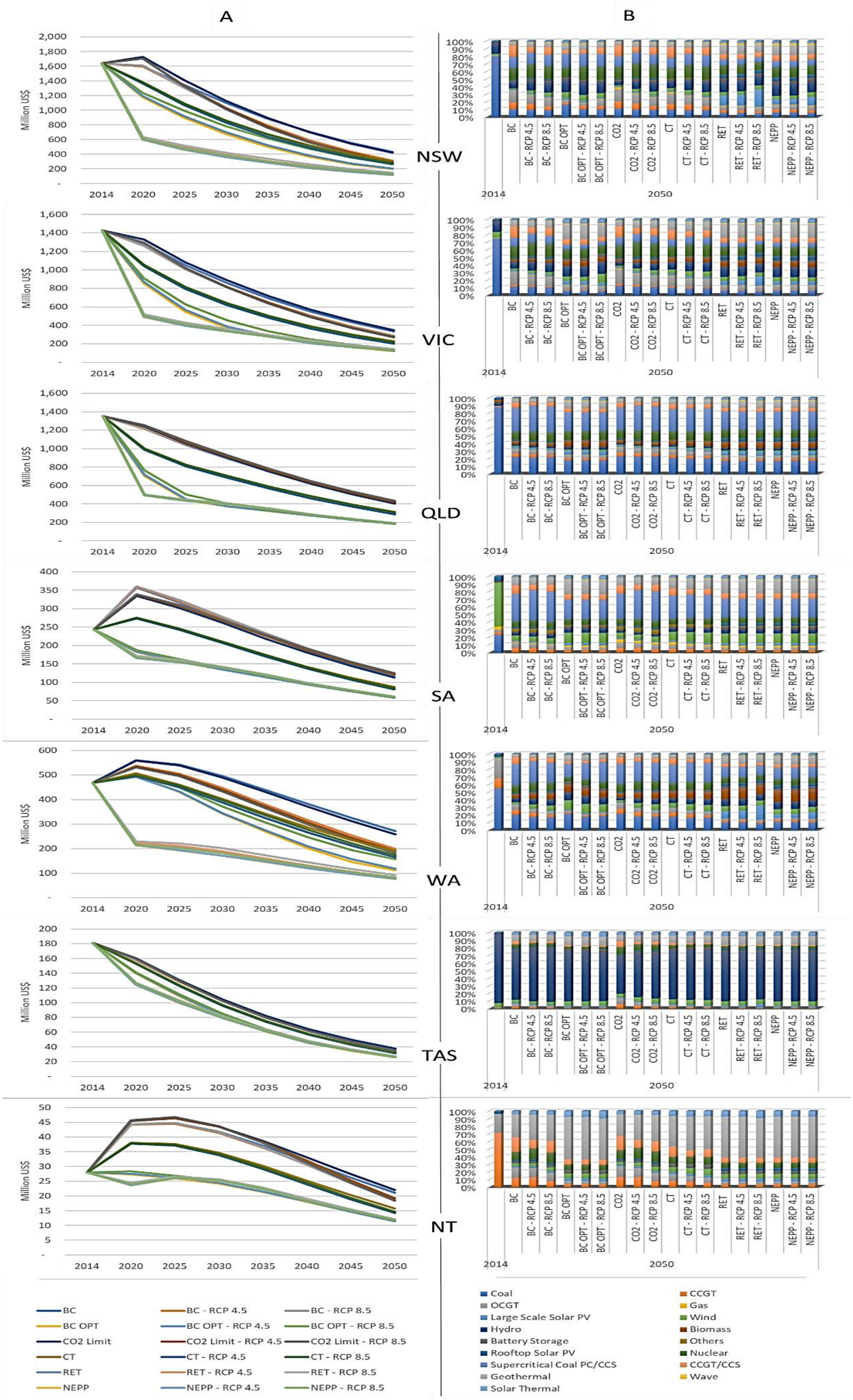

Figure 5. 18: Social Cost Discounted to 2014 shown in Panel A and share shown in Panel B.

Compared to the CO2 scenario which is US$28 million lower than the BC scenario, the carbon tax policies appears to be a better policy option than emission reduction target due to the relative lower social cost at the same capacity mix as the BC and CO2 scenarios.

5.5.2.2. Sales Revenue

The LEAP-OSeMOSYS model was used to calculate the sales revenue for the policy and climate change scenarios using state-level retail electricity prices. Electricity prices in Australia are based on two plans which are either standard plans (regulated by the government) and market plans (designed by electricity retailers). Market plans have competitive rates, though they come with discounts and other related incentives to reduce the cost of electricity. Therefore, this study applied a market offer price due to (i) assumptions that consumers will opt for a more affordable market offer over standard offer, and (ii) lack of available data on household choice of electricity plans. The study applies retail electricity prices from (AEMC, 2017).

The results are presented in Figure 5.19 and show that the RET scenario had the highest sales revenue in NSW and WA with revenue generation reaching US$ 4,841.1 billion and US$ 2,051 billion (in real 2014 dollars) in 2050. Also, due to increased climatic conditions, the model projects sales revenue in NSW and WA to reach US$5,145 billion and US$ 2,128 billion, respectively, if adopting the RET-RCP 8.5 scenario. Similarly, results from QLD, SA and TAS showed higher sales revenue in the RET – RCP 8.5 scenario, compared to other policy and climate change scenarios considered in this study.

In terms of share of power plants contributing to sales revenue, the model's results reveal that revenue generation by power plants in each state depends on the scenario considered. For example, sales revenue generation from CCGT with CCS was higher in the BC scenario, compared to sales contribution in the CT scenario. This is because the CT scenario had its share of sales revenue generation declining by more than half compared to the BC scenario. The share of sales revenue for renewables such as solar and wind technologies where higher than other renewables (wave, geothermal and biomass power plants) across the states and territory.

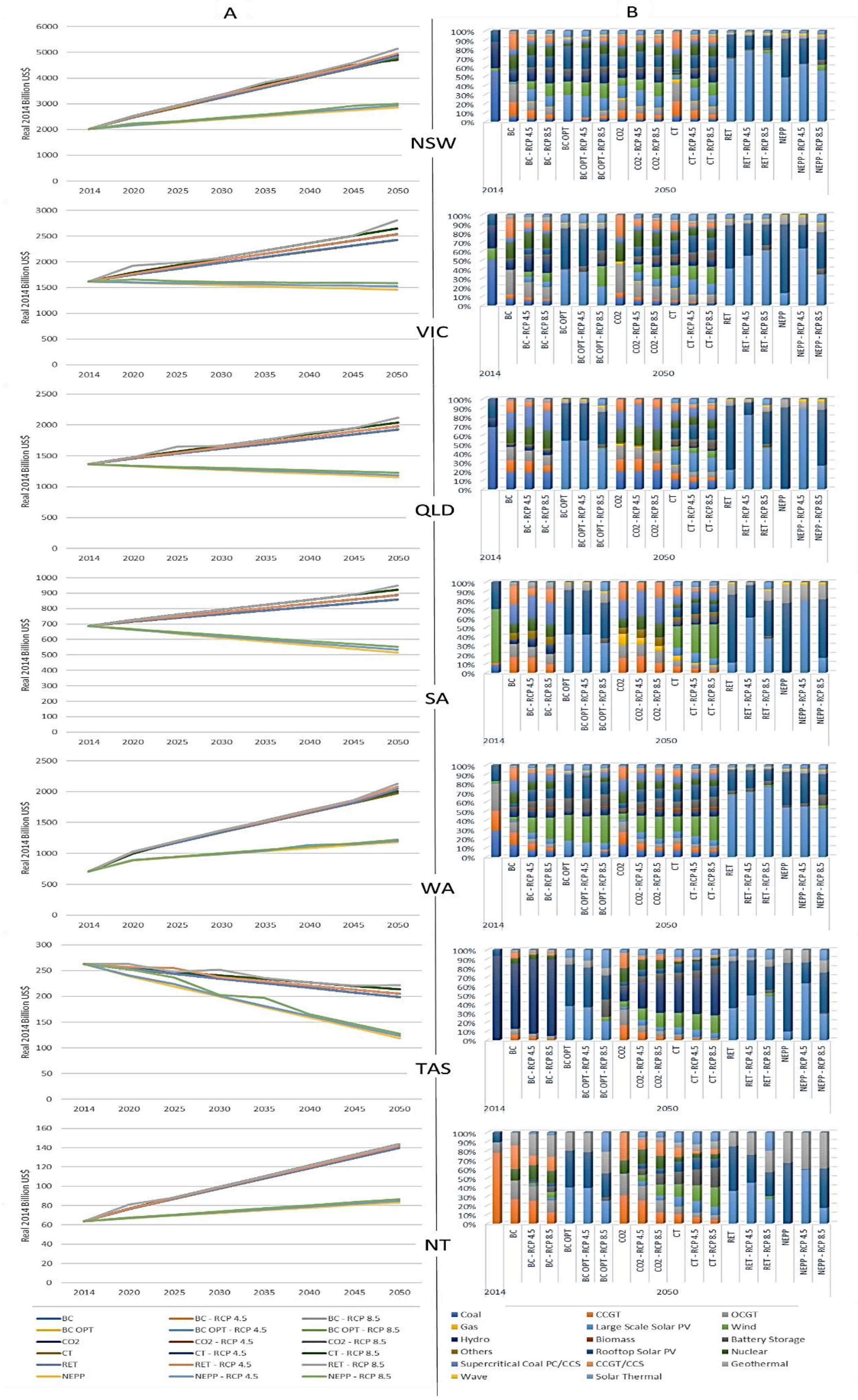

Figure 5. 19: Sales Revenue in Panel A and Share of Sales by Power Plant in Panel B.

An interesting observation was seen in sales revenue for rooftop solar PV which appeared to double under climate change scenarios. Here, the sales revenue is assumed to be income earned by prosumers who sell renewable electricity to the power grid. These results imply that electricity retailers (and possibly electricity generators) and prosumers will increase their revenue generation and income under the RET scenario considering the presence or absence of climate change conditions. Therefore, investments should be shifted to renewable energy technologies in order to boost electricity sales revenue in the future.

5.5.2.3. Cost of Electricity Production

The model results for cost of electricity production in each scenario is presented in Figure 5.20. The results reveal that the cost of generating electricity in Australia will increase from US$ 8.5 billion in 2014 to US$ 24 billion in 2050 under the BC scenario, at an annual growth rate of 3.01%. Temperature changes might exercise effects on power generation which will decrease production cost by 29% and 32% in the BC – RCP 4.5 and BC – RCP 8.5 scenarios, respectively. Results for alternative scenarios show that production cost increases in the CO2 scenario by 3.42% which is 0.41% higher than the BC scenario. This implies that imposing state-level emission reduction target may lead to higher cost of production since the electricity mix will mainly consist of fossil fuel plants with those fitted with CCS technologies. The CCS technologies cause additional cost to the production of electricity. However, looking at the CT scenario reveals that electricity production cost is lower than the BC and CO2 scenarios.

Considering impact of climate change, production costs are lower in the CO2 – RCP 8.5 (37%) than the CO2 policy scenario, while CT – RCP 4.5 had a lower production cost (27%) under the CT scenario by 2050. The reason for this is because of the introduction of renewables to supplement the decline in efficiency of thermal power plants. Comparing the RET and NEPP scenarios, electricity production cost declines by 2.33% and 2.40%. However, climatic factors were observed to have more effect in the RET (about 1.8% increase in production cost) than the NEPP. Thus, the NEPP scenario presents the most favourable approach to cost savings associated with producing electricity void of climate change impacts. Within the states and territory, the cost of electricity production began to drop before mid-century in NSW, VIC, WA and NT. The drops in production cost mainly occurred in the CO2 – RCP 8.5 scenario which may owe to technology substitution when rising temperatures will force the switching of fossil fuel to renewables, even in the CT and CO2 scenarios. Therefore, fuel switching should be expected in the electricity generation mix under climate change conditions, having in mind that cost of producing electricity all over Australia will be affected.

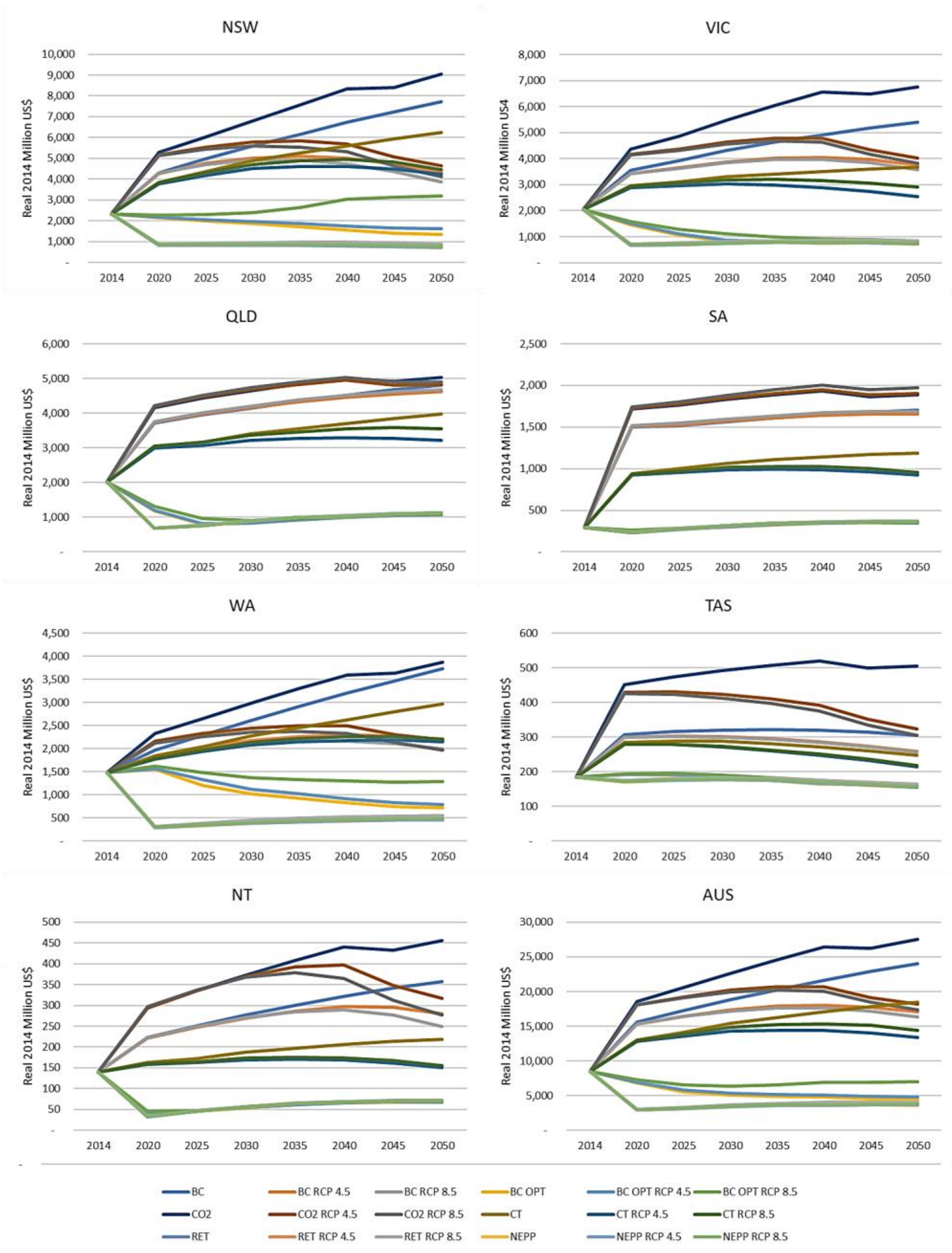

Figure 5. 20: Cost of Electricity Generation.

5.5.2.4. Long Run Marginal Cost

The marginal cost of electricity can be defined as the extra cost associated with the increase in supplying a specified amount of electricity (Kemp et al., 2011). Electricity tariffs are based on marginal cost calculations which establish prices for electricity sold by producers. The marginal cost indicates how much retailers must pay if they require additional units of electricity supply in the future, and can be calculated on the short-run and long-run. The LRMC of electricity is the expected marginal cost of extra capacity plus marginal electricity production cost which reflects the cost of incremental change in demand. The short-run marginal cost of electricity does not require capacity costs but substitutes the future cost of unsupplied electricity (Porat et al., 1997).

Calculating the LRMC of electricity is of importance to this study for benefits of determining investment priorities. Investment in capacity expansion can be delayed or retried if wholesale electricity prices are lower than the LRMC. Alternatively, if wholesale electricity prices rise to more than the LRMC, then it is necessary to expand generation capacity to lower electricity prices towards the LRMC. However, an electricity market is expected to sustain a long-term situation in which prices are higher or lower than the LRMC of electricity (Administrator, 2012). Also, marginal cost base pricing can lead to a more efficient utilisation of electricity (Malik and Al-Zubeidi, 2006). Therefore, LRMC of electricity was estimated using the AIC method presented Eq. (4.24) for an 18-year period (2014-2032 and 2033-2050). The results are presented in Table 5.5 which show the five individual NEM states, the NEM, SWIS of WA, and I-NTEM for the NT. For comparison, see Table 4.7 showing wholesale electricity price trends from 2016 – 2019.

The results reveal that under the BC scenario, LRMC was lower than wholesale electricity prices across the states. However, an observation of price trends in Table 5.5 shows that a declining trend of wholesale electricity prices (2017-2020) which may become higher than LRMC, will result in the need to expand generation capacity. Results from the alternative scenarios show that CO2 scenario had the highest LRMC of electricity across the states. If the 2019-20 wholesale electricity price trend continues, then an emission reduction target policy will result in the need for additional capacity before 2032 in NSW, QLD and SA.

Table 5. 5: Long Run Marginal Cost of Electricity (US¢/kWh).

	NSW		VIC		QLD		SA		TAS		NEM		WA (SWIS)		NT (I-NTEM)	
	2032	2050	2032	2050	2032	2050	2032	2050	2032	2050	2032	2050	2032	2050	2032	2050
BC	4.40	1.72	4.66	1.97	5.76	2.33	6.89	2.77	2.78	1.27	4.90	2.01	3.97	1.60	5.59	2.10
BC RCP 4.5	3.76	0.95	4.03	1.30	5.66	2.17	6.79	2.62	2.56	1.05	4.56	1.62	3.20	0.93	5.35	1.63
BC RCP 8.5	3.61	0.88	3.90	1.20	5.62	2.13	6.75	2.56	2.49	1.00	4.48	1.55	3.04	0.84	5.31	1.43
BC OPT	1.36	0.30	0.86	0.26	1.18	0.52	1.36	0.57	1.55	0.64	1.26	0.46	1.44	0.31	1.12	0.40
BC OPT RCP 4.5	1.43	0.35	0.86	0.26	1.17	0.51	1.34	0.55	1.55	0.63	1.27	0.46	1.55	0.33	1.11	0.39
BC OPT RCP 8.5	1.80	0.72	1.05	0.28	1.23	0.50	1.36	0.54	1.57	0.62	1.40	0.53	1.95	0.54	1.14	0.40
CO2	5.38	2.02	5.99	2.46	6.44	2.43	8.08	3.07	4.31	2.11	6.04	2.42	4.54	1.66	7.55	2.69
CO2 RCP 4.5	4.34	1.01	4.83	1.40	6.35	2.27	8.01	3.00	3.58	1.31	5.42	1.80	3.57	0.93	7.32	1.84
CO2 RCP 8.5	4.09	0.93	4.61	1.27	6.32	2.24	8.00	3.00	3.41	1.19	5.29	1.72	3.38	0.83	7.16	1.59
CT	3.80	1.40	3.52	1.34	4.71	1.92	4.72	1.94	2.47	1.04	3.84	1.52	3.41	1.27	3.73	1.29
CT RCP 4.5	3.40	0.93	3.08	0.88	4.34	1.51	4.25	1.46	2.28	0.87	3.47	1.13	3.04	0.91	3.29	0.88
CT RCP 8.5	3.49	1.01	3.18	0.97	4.48	1.62	4.28	1.45	2.26	0.85	3.54	1.18	3.10	0.93	3.33	0.89
RET	0.66	0.17	0.82	0.28	1.28	0.54	1.43	0.59	1.55	0.66	1.15	0.45	0.63	0.20	1.18	0.41
RET RCP 4.5	0.65	0.17	0.81	0.27	1.26	0.53	1.40	0.57	1.53	0.64	1.13	0.44	0.62	0.20	1.17	0.41
RET RCP 8.5	0.70	0.18	0.83	0.27	1.25	0.50	1.39	0.55	1.53	0.61	1.14	0.42	0.68	0.22	1.16	0.41
NEPP	0.85	0.26	1.07	0.46	1.66	0.90	1.82	0.99	1.85	1.09	1.45	0.74	0.81	0.33	1.62	0.69
NEPP RCP 4.5	0.85	0.26	1.05	0.44	1.64	0.88	1.80	0.96	1.84	1.06	1.43	0.72	0.81	0.32	1.60	0.68
NEPP RCP 8.5	0.88	0.27	1.03	0.43	1.62	0.85	1.78	0.92	1.69	1.03	1.40	0.70	0.84	0.34	1.59	0.67

Meanwhile, the wholesale electricity prices were observed to be higher than LRMC of WA and NT under the six policy scenarios considered in this study. This implies that the current mix of generation capacity in WA and NT will need to be expanded by 2032 or opt for a more sustainable mix of generation capacity that will lower wholesale electricity prices. This can be seen in BC OPT, RET and NEPP scenarios where LRMC was between US¢0.17kWh to US¢1.85kWh for the seven states and territory. Also, climate change scenarios were observed to reduce LRMC of electricity in fossil fuel dominated scenarios, but increased LRMC in scenarios with mainly renewable energy technologies. The implication is, higher investment in renewables have the capacity to reduce wholesale electricity prices which will result in the decrease of retail electricity prices for the final consumers.

5.5.2.5. Cost-Benefit Analysis

The LEAP-OSeMOSYS model was used to conduct a cost-benefit analysis to identify suitable policy scenarios that can lead to emission reduction and resource savings. The results are presented in Table 5.6 which shows that cumulative costs and benefits of the alternative scenarios relative to the BC scenario for the study period were at 5% and 10% discount rate. The results show that emission reduction policies in CO2 scenario results in added cost to the economy in terms of resource requirement, environmental externalities, and investment in electricity generation capacity. The introduction of carbon tax into the model in CT scenario led to savings of about US$ 340.1 billion in installation cost, US$ 1,360 billion in resource savings, and US$ 108.2 billion in environmental externality benefits, accrued to the Australian economy by 2050.

In terms of net present value (NPV), renewable dominated BC OPT, RET and NEPP scenarios had about four times higher benefits than CT scenarios, with NPV ranging from US$ 5,430 billion to US$ 5,935 billion, at 5% discount rates. The results of RCP 4.5 and RCP 8.5 conditions for each policy scenario show that in fossil fuel dominated scenarios, temperatures changes result in declining economic benefits in terms of resources, externalities, and investment savings for generation capacity. However, climate change conditions had insignificant impact on the high economic benefits in the RET and NEPP scenarios. Likewise, the CT scenario was not affected by climate change conditions.

Table 5. 6: Cumulative costs and benefits for the period 2014-2050 for Alternative scenarios relative to the BC scenario at 5% and 10% discount rate.

Billion 2014 US$	BC RCP 4.5	BC RCP 8.5	BC OPT	BC OPT RCP 4.5	BC OPT RCP 8.5	CO2	CO2 RCP 4.5	CO2 RCP 8.5	CT	CT RCP 4.5	CT RCP 8.5	RET	RET RCP 4,5	RET RCP 8.5	NEPP	NEPP RCP 4.5	NEPP RCP 8.5
5%																	
Electricity Generation	-21.6	-5.6	-958.6	-940.6	-859.8	38.5	-30.1	-14.0	-340.1	-364.8	-321.7	-1139.2	-1131.1	-1075.9	-1173.0	-1168.5	-1138.6
Resources	-413.6	-483.5	-4225.6	-4218.7	-4195.4	3679.9	2537.5	2278.3	-1360.1	-1813.0	-1782.3	-4485.0	-4485.2	-4485.6	-4484.0	-4484.0	-4484.4
Environmental Externalities	-24.4	-28.5	-246.1	-245.6	-241.7	77.1	36.5	23.7	-108.2	-128.3	-126.1	-278.0	-278.1	-278.1	-278.0	-278.0	-278.0
Net Present Value	-459.5	-517.6	-5430.3	-5404.9	-5296.9	3795.5	2543.9	2288.1	-1808.4	-2306.2	-2230.1	-5902.3	-5894.3	-5839.6	-5935.0	-5930.4	-5901.0
10%																	
Electricity Generation	-6.2	1.4	-440.4	-431.8	-397.0	17.7	-2.8	5.7	-145.4	-153.4	-136.1	-592.4	-588.5	-564.6	-608.8	-606.5	-592.3
Resources	-151.3	-171.2	-2255.6	-2250.8	-2237.2	1889.4	1470.2	1379.4	-677.4	-852.1	-840.1	-2480.7	-2480.9	-2481.3	-2479.8	-2479.7	-2480.2
Environmental Externalities	-9.1	-10.2	-131.7	-131.3	-129.3	43.7	28.0	23.7	-53.6	-61.6	-60.7	-155.9	-155.9	-155.9	-155.8	-155.8	-155.8
Net Present Value	-166.5	-180.0	-2827.7	-2814.0	-2763.5	1950.7	1495.4	1408.7	-876.4	-1067.2	-1036.9	-3229.0	-3225.2	-3201.8	-3244.4	-3242.0	-3228.3

Note: minus (-) sign represent benefit and plus (+) sign represent added cost to the economy.

Table 5. 7: Cumulative discounted GHG Savings and Cost of Avoiding GHGs.

	Discount rate	BC RCP 4.5	BC RCP 8.5	BC OPT	BC OPT RCP 4.5	BC OPT RCP 8.5	CO2	CO2 RCP 4.5	CO2 RCP 8.5	CT	CT RCP 4.5	CT RCP 8.5	RET	RET RCP 4,5	RET RCP 8.5	NEPP	NEPP RCP 4.5	NEPP RCP 8.5
GHG Savings (MtCO2eq)		1080.2	1213.6	6270.1	6223.4	5695.0	151.9	1299.4	1488.4	2968.6	3580.0	3351.3	7917.9	7917.8	7917.9	7918.1	7918.0	7917.9
Cost of Avoiding GHGs (U.S. Dollar/Tonne CO2e)	5%	-120.4	-108.2	-258.6	-255.1	-250.1	129.5	314.0	260.2	-165.9	-176.3	-165.4	-266.3	-265.9	-263.5	-268.0	-267.8	-266.4
	10%	-41.7	-36.7	-132.1	-130.1	-128.6	68.7	186.9	156.2	-83.3	-82.8	-78.9	-145.8	-145.6	-144.5	-146.5	-146.4	-145.8

Note: minus (-) sign represent benefit and plus (+) sign represent added cost to the economy.

This implies that a CT policy will be more effective under climate change conditions in comparison to the BC and CO2 scenarios. Notwithstanding, having an electricity system consisting mainly of renewable energy technology with an effective energy efficiency policy can boost economic benefits that will not be affected by rising temperatures. Finally, lower discount rate of 5% were observed to favour the deployment of renewable energy technologies, while CT scenario losses about half of its economic benefits when discount rates increase to 10%. This implies that lower discount rates favour investment in renewable energy technologies in Australia. Therefore, a key policy approach will be the provision of guaranteed long-term finance at a lower discount rate to increase the share of renewables in the Australian energy mix.

5.5.2.6. Sensitivity Analysis

A sensitivity analysis was estimated to identify the sensitivities of the scenarios to changes in investment, fuel and operation cost. This is based on the study by (Samadi, 2017) who identified four types of plant-level costs which include, capital costs, fuel costs, the market costs of GHG emissions, and non-fuel O&M costs (i.e. fixed and variable). The capital cost of energy technologies have projected to decline before 2050 as shown in Table 4.4 in chapter 4, while fossil fuel price have been highly unstable over the years, where future prices are uncertain (Will Devlin et al., 2011). Also, the International Renewable Energy Agency have projected reductions to O&M cost for solar and wind energy by 2025 (Taylor et al., 2016). Therefore, it is necessary to examine changes in costs associated with investment, fuel, and O&M for energy technologies from 2014 to 2050. This study's sensitivity analysis varied investment, fuel and O&M costs' values by ±20%.

The results are shown in Figure 5.21 where charts on the left panel present the NPV and charts on the right panel show the percentage changes of the alternative scenarios compared to BC scenario for Australia. The results indicate that the large share of renewable energy technologies in RET and NEPP made the scenarios less expensive than the BC scenario, followed by the BC OPT scenario. More specifically, the results show that changes in investment cost and fuel prices will have less impact on RET and NEPP policy, as well as its associated climate change scenarios.

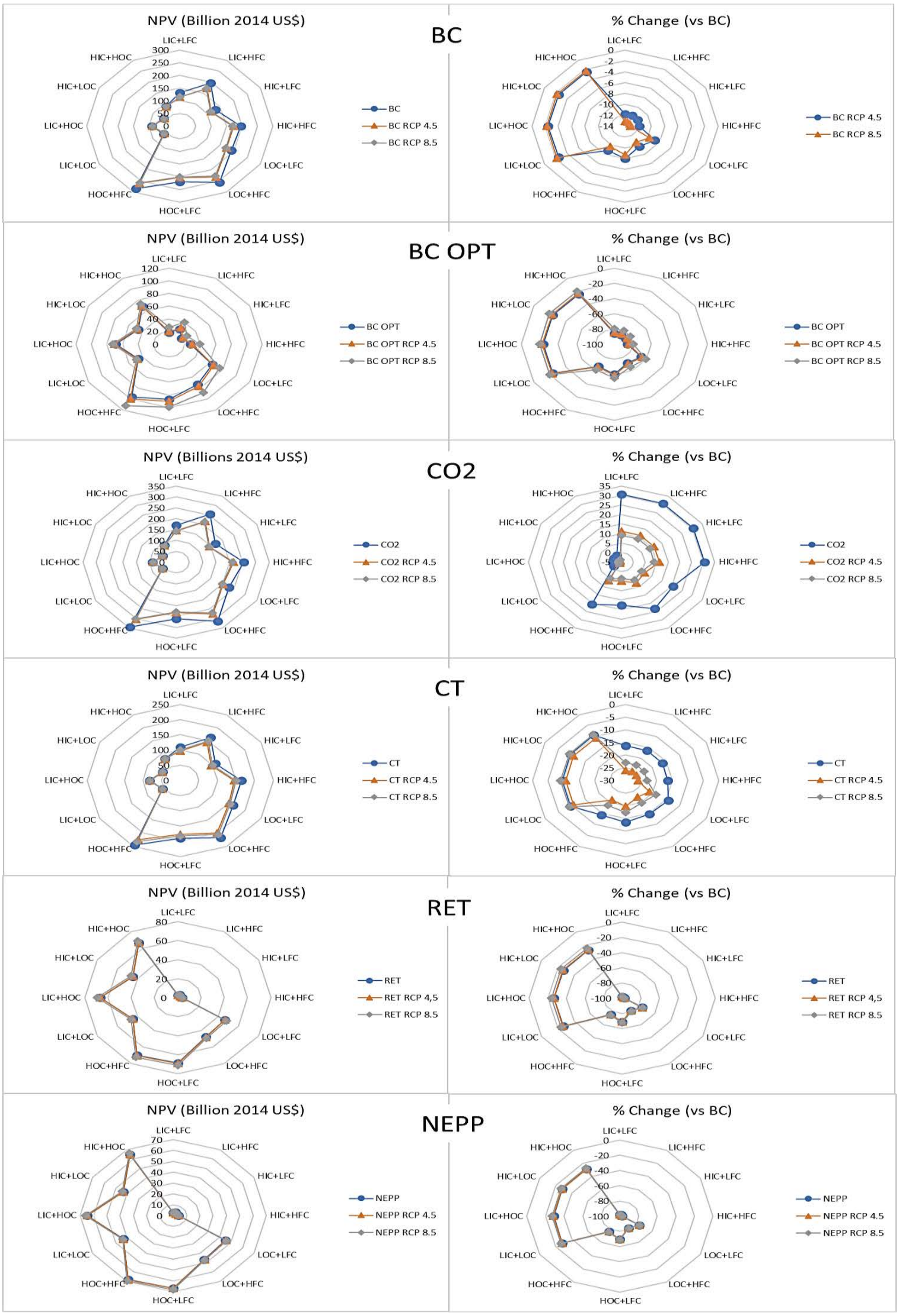

Figure 5. 21: Sensitivity Analysis of Scenario Performance.

Note: LIC: low investment cost, HIC: high investment cost, LFC: low fuel cost, HFC: high fuel cost, LOC: low operating cost, HOC: high operating cost.

In terms of changes in O&M costs and fuel price, the results show that CO2 scenario will respond negatively with higher prices along the electricity supply chain. However, associated climate conditions (i.e. CO2 – RCP 4.5 and 8.5) show reduced impact of the changes in O&M costs and fuel prices. This is attributed to the introduction of renewables to meet the shortfall in the supply mix, since temperature changes will affect output from thermal power plans. The CT scenario in the context of functional carbon tax in Australia was observed to be about 14% - 15% less expensive than the BC scenario which implies about 15% economic savings in electricity production.

Across the scenarios, climate change was observed to increase the economic savings in O&M costs and fuel price in the CT scenario, but increase cost in the BC OPT scenario. This may be due to the need to increase installed capacity of renewable energy technologies when temperature increases in the BC OPT scenario, which is based on cost optimisation. In terms of changes in investment and O&M costs, the sensitivity analysis shows that BC OPT, RET and NEPP were 24%, 27% and 29% less expensive than BC scenarios. The associated RCP 4.5 and RCP 8.5 climate change conditions showed only a 1%-2% reduction in economic savings due to changes in investment and O&M costs. The summary of our sensitivity results reveal that RET, NEPP and BC OPT scenarios were the most resilient to changes in the cost of investment, O&M costs, and fuel prices.

In detail, the after mentioned scenarios were between 86% - 98% less expensive during changes in investment and fuel prices than BC scenario; between 61% - 82% less expensive during changes in O&M costs and fuel prices with HOC + LFC being at lower bounds, and between 24% - 29% less expensive than BC scenario when investment and O&M costs become unstable. Therefore, government policies should aim at decarbonising the power grid with an improved energy efficiency program that can result in demand reduction. This will make the electricity grid more resilient to fluctuations in the cost of energy technologies and fuel prices.

5.5.3. Environmental Analysis

5.5.3.1. Cumulative GHG Emissions

The LEAP model contains the relevant Global Warming Potential factors required for environmental analysis. The emissions factor derived from the Intergovernmental Panel on Climate Change's Fifth Assessment Report with climate feedback (IPCC, 2018a) was applied in this study to estimate the GHG emissions from the electricity sector. The results are presented in Figure 5.22 which illustrate the cumulative GHG emissions for policy and climate change scenarios compared to BC scenario. The results show that RET and NEPP scenarios had the lowest cumulative emission among the alternative scenarios when compared to BC scenario. This is followed by the BC OPT scenario with cumulative GHG emission of 6.3 million $MtCO_2eq$ from 2014 to 2050.

Under climate change conditions, emissions increase in the BC – RCP 4.5 and BC – RCP 8.5 scenarios by 46 and 572 million $MtCO_2eq$. In the CO2 scenario, emissions were higher than the BC scenario from 2014 to 2045 with increasing emissions from 22 to 60 million $MtCO_2eq$, which could decline to 154 million $MtCO_2eq$ below the BC scenario. In contrast, CT scenario had higher emissions reduction potential, compared to the BC scenario with 2.9 million $MtCO_2eq$. The climatic conditions tend to differ from the climate scenarios in BC OPT because the CO2 – RCP 4.5 and CO2 – RCP 8.5 had a reduction of about 1.2 and 1.3 million $MtCO_2eq$, respectively, while CT – RCP 4.5 and CT – RCP 8.5 had about 0.6 and 0.4 million $MtCO_2eq$ for the study period.

The results imply that the current emission reduction target may be less effective in reducing emissions from the electricity sector, but carbon tax presents a better alternative with higher emission reduction potential. However, if the future temperatures exceed +2^{0}C, our optimisation model predicts that the electricity sector in the CO2 and CT scenarios will switch to more sustainable source of electricity, which apparently are renewables. The renewables include biofuel use which may have some negative effects on the environment and economy, in terms of agriculture, water, and biofuel instigated carbon emissions (Sterman et al., 2018, Policies, 2017, Campbell and Doswald, 2009, Holtsmark, 2015). This identified shortcoming was not addressed in this study, but can be a topic for future research.

Summing up GHG emissions analysis, this study found that RET and NEPP present the highest potential in emission reduction which is not affected by climate change scenarios, and this shows that renewable energy technologies could play an important role in order for Australia to meet its emission reduction goals, and transform the economy towards a low carbon society.

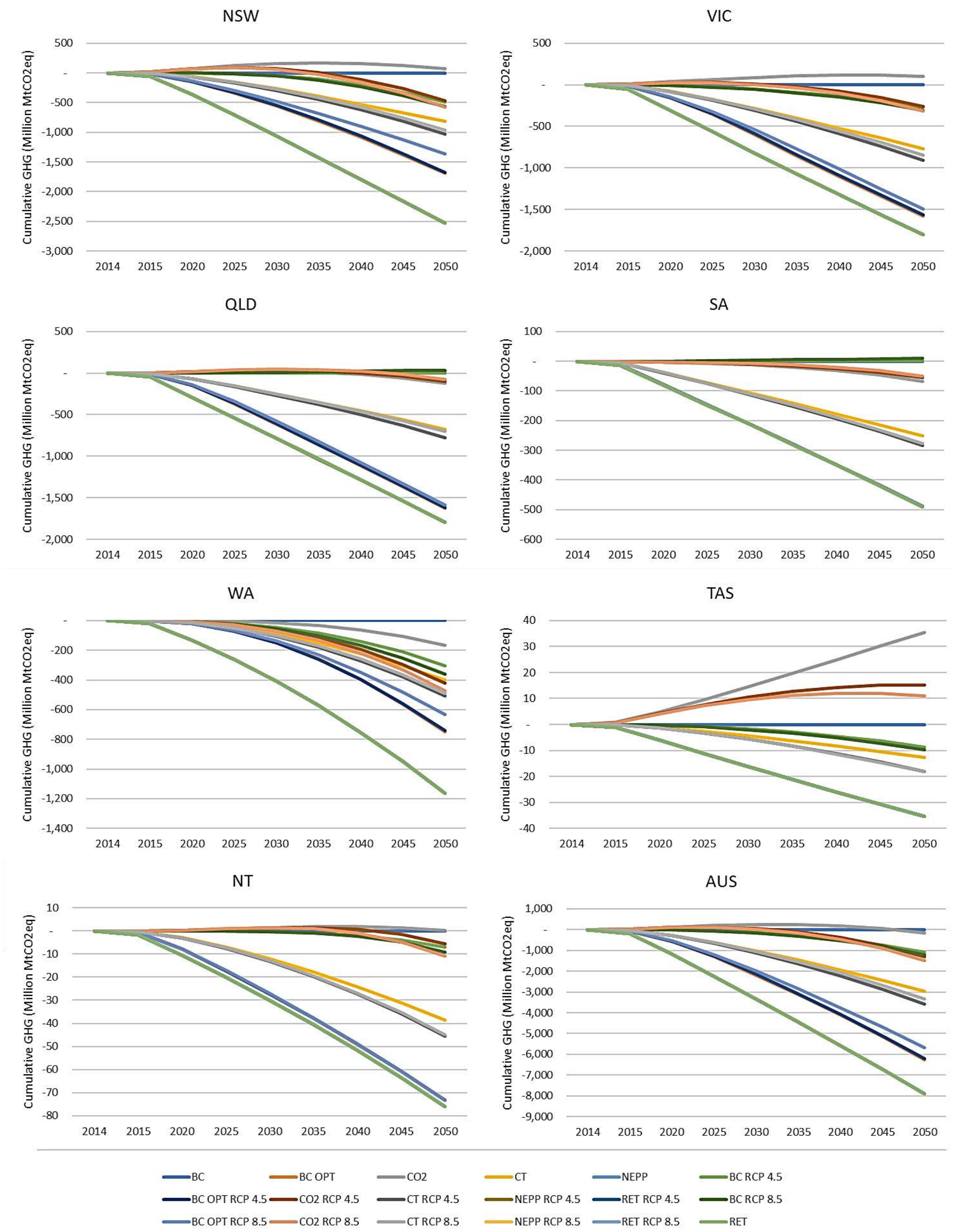

Figure 5. 22: Cumulative GHG Emission (Alternative Scenarios Compared to BAU Scenario).

5.5.3.2. Cumulative GHG Savings and Cost of Avoided GHG Emissions

We extended our environmental analysis to examine the cumulative GHG emission savings and the cost of reducing GHG concentration in the atmosphere (as US$/tonne of CO_2eq not emitted compared to BC scenario). The results are presented in Table 5.7, showing that unlike the cost-benefits results in Table 5.6, discount rates have no effect on GHG savings for the study period. However, emission reduction target policies in the CO2 scenario are observed to increase the cost of avoiding GHGs in Australia, while still in CO_2 scenario context, rising temperatures will double the cost before 2050. While the CO_2 scenario results in abatement cost, implementing a carbon tax policy results in economic benefits in the BC OPT, RET and NEPP scenarios under a 5% discount rate.

Electricity generated from renewable sources accrue lower or no emissions in the RET and BC OPT scenarios, whereas a relatively lower electricity demand increase economic benefits in the NEPP scenario. A survey conducted in (Jayanthi and Christine, 2016) shows that many Australian energy-intensive industries abandoned energy management projects after carbon tax was repealed in 2014. Most respondents in the study agreed that carbon tax drove companies to improve energy efficiency and reduce emissions. Other studies such as (Siriwardana et al., 2011) highlights that the introduction of carbon tax policy in Australia led to a 12% reduction in emissions in the first year of its introduction alone, but (Ge, 2014, Rahman, 2013) argue that carbon tax led to an increase in inequality and housing cost, as well as decrease in income and job loss. Although the inter-sectorial impact was not examined in this study, future research can address this research limitation. Notwithstanding, our model has shown that carbon tax policy is more effective in emission reduction than the current emission reduction target in Australia.

5.5.4. Model Validation

To verify the accuracy of the model developed in this study, official electricity generation data from 2014 to 2017 were retrieved from the Department of Environment and Energy (Energy, 2017b). The official data was compared with the LEAP-OSeMOSYS model output for power generation (from the BC scenario), and results are presented in Table 5.8. Comparing the official data to the model output shows a closely matched data for 2014 with an absolute percentage error (APE) of 0.00%. The APE from 2015-2017 for the seven states and territory, and the national data were between -0.04% and 3.57%. The mean average percentage error (MAPE) across the states and territory range between 0.34% to 1.41%. Therefore, the highest error for electricity generation that will be obtained in this paper will be 1.41%. Since errors associated with the modelled electricity generation values are within acceptable limits, the LEAP-OSeMOSYS model can be used to model the Australian electricity system for future years, and as well derive useful policy implications.

Table 5. 8: Electricity Generation and Energy Demand Official Data and LEAP Data from 2014 to 2017.

	2014	2015	2016	2017	MAPE
LEAP-AUS	247843.38	252391.80	257418.16	259669.66	
Actual Data	247843.38	252390.83	257428.59	259654.62	
APE	0.00%	-0.04%	0.40%	-0.58%	0.34%
LEAP-NSW	67295.43	64155.20	70255.67	70883.14	
Actual Data	67295.43	64159.15	70250.22	70876.10	
APE	0.00%	0.62%	-0.78%	-0.99%	0.79%
LEAP-VIC	52803.16	56680.52	54570.62	52359.72	
Actual Data	52803.16	56678.51	54561.69	52361.37	
APE	0.00%	-0.35%	-1.64%	0.32%	0.77%
LEAP-QLD	60479.97	68120.42	67374.09	70748.77	
Actual Data	60479.97	68117.05	67387.13	70736.12	
APE	0.00%	-0.49%	1.93%	-1.79%	1.41%
LEAP-SA	13119.97	13027.46	13080.71	11609.58	
Actual Data	13119.97	13026.31	13082.42	11608.03	
APE	0.00%	-0.88%	1.30%	-1.33%	1.17%
LEAP-WA	36679.59	37779.89	38729.03	40483.24	
Actual Data	36679.59	37781.92	38736.80	40488.86	
APE	0.00%	0.54%	2.01%	1.39%	1.31%
LEAP-TAS	13999.46	9631.78	10343.13	10602.49	
Actual Data	13999.46	9630.89	10344.33	10600.79	
APE	0.00%	-0.92%	1.15%	-1.61%	1.23%
LEAP-NT	3465.82	2996.54	3064.90	2982.72	
Actual Data	3465.82	2997.00	3065.99	2983.34	
APE	0.00%	1.55%	3.57%	2.09%	2%

5.6. Discussion

The simulation results identified three least generation expansion options with effective emission reduction policies for Australia electricity sector. They include the cost optimization (BC OPT), renewable energy target (RET), and energy productivity (NEPP) scenarios. The difference between the scenarios was that BC OPT had a 90-95% renewable electricity supply, while the RET and NEPP attained a 100% renewable supply by 2050, comprising solar, wind, and large-scale battery storage systems. Technologies in BC OPT scenario were sensitive to temperature variations than RET and NEPP.

However, NEPP scenario differs from RET because an integrated resource planning (IRP) approach is applied, where supply-side options with 100% renewables are combined with demand side energy efficiency options which increases productivity to 40%. The IRP approach was identified in studies such as (Shrestha and Marpaung, 2006) as the most effective approach in emission mitigation and energy resource conservation. BC scenario predicts that electricity generation in Australia will increase from 292 TWh in 2014 to 533 TWh in 2050. The emission reduction target (CO_2) scenario were observed to aim more at fossil fuel, while renewable energy was constrained in the scenarios. On the other hand, carbon tax policy (CT) scenario had higher inclusion of renewable energy technologies which range from 44% to 88% across the country.

Economically, the model shows that emission reduction target will result in added cost to the economy, while carbon tax policies will yield economic benefits of about US$ 1.8 billion in installation cost, resource savings, and environmental externalities by 2050. Although renewable dominated scenarios present the highest economic benefits in terms of policy intervention, and lower discount rates, yet they were observed to favour the penetration of renewables on the long run. Also, our sensitivity analysis reveals that the renewable dominated scenarios were between 86% - 98% less expensive than the BC scenario, and more resilient to climate change conditions and changes in fuel prices, capital cost, as well as O&M cost of energy technologies. In terms of social cost, the CT scenario approach was poised to be a better policy approach to emission reduction than CO_2 scenario. However, sales revenue was higher in the RET scenario compared to other alternative scenarios.

This study equally observed that under climate change conditions, sales revenue for solar rooftops doubled in the RCP 4.5 and tripled in the RCP 8.5 scenarios. The cost of generating electricity was observed to be the lowest in NEPP scenario, compared to other policy scenarios. Climatic conditions were also observed to lead to lower electricity production cost in the CT and CO2 scenarios due to switching with renewable options to meet rising demand and address declining output from thermal power plants. The results of the LRMC show that CO_2 scenario had the highest LRMC of electricity across Australia for the period of 2032 and 2050. Be that as it may, climate change was observed to reduce the LRMC in fossil fuel dominated scenarios while increasing LRMC in renewable dominated scenarios. Results from our environmental analysis show that emission reduction target increases cumulative emissions which surpass the BC scenario, while future temperatures may double the emissions from same BC scenario. Further, the CO2 scenario was observed to double the cost of avoiding GHGs in Australia courtesy of global warming before 2050.

The model highlights a significant impact on electricity supply and GHG emissions for future low carbon pathways. The alternative scenarios intend to show that energy affordability, reliability, and emission reduction can be achievable in Australia by 2050. No doubt, GHG emissions will reduce under the alternative policies, but given the 2050 milestone, it will require a radical policy to put the Australian economy on the map of countries with clean energy. The radical policy identified in this study was RET scenario which proved effective in terms of a reliable electricity supply, affordable electricity prices, and effective emission reduction.

Climate change presents a challenge in the implementation of energy policies such as the emission reduction target, carbon tax, and cost optimization approach. Regardless, our model suggests that this situation can be managed with increase in supply from renewable electricity. Increased dispatch of renewable electricity during rising temperature showed that rising demand can be met, but the cost implication was observed to be expensive as additional capacity might be constructed to meet summer or winter peak loads. Therefore, government intervention through policies favouring higher investment in renewable is required.

5.7. Conclusions

This study applied the concept of combining backcasting and exploratory scenarios to explore the least-cost electricity generation expansion options, while examining the effectiveness of emission reduction policies under climate change. The LEAP-OSeMOSYS model was used in this study, and the Australian electricity sector was selected as a case study. Six policy scenarios under two climate change conditions were developed and analysed through comparative analysis, taking on board their technical, economic and environmental potentials. The results show that higher integration of renewables into the future energy system will yield great potential for energy affordability, reliability and reduced GHG emissions, respite future climate conditions. The least-cost scenarios modelled in this study are based on technical and socioeconomic parameters used in the LEAP-OSeMOSYS simulation, which will likely evolve in the future. The RCP 4.5 and RCP 8.5 climate scenarios are consistent with socioeconomic assumptions based on possible changes in human GHG emissions. However, it should be noted that climate projections suffer from uncertainties and the optimisation model expanded generation capacity based on resource availability, cost implications, and emission constraints imposed. Changes in energy prices, cost of energy technology and technological progress can result in more optimal expansion options.

Although energy efficiency was assumed to decrease demand in the NEPP scenario by 40%, different socioeconomic situation and consumer behaviours (external to the model) may alter energy demand and affect future modelling outcomes. However, improvement in future energy system modelling will further expand the least-cost generation options and present more strategies for future energy system. The techno-economic and environmental analysis demonstrates that the best approach in combating climate change impact on electrical system is to adapt the system to future climate conditions, while mitigating GHG emissions. As this approach involves the transitioning of the current stock of fossil fuel plants in Australia’s electricity market to renewables and battery storage systems, available funds for investment might become a paramount issue on the short term. However, the vulnerability of the power generating system to climate change, cumulative fuel cost and rise in emissions tend to change the status-quo on the long run.

The rising cost of wholesale and retail electricity prices may force the government to implement policies forcing power companies to source for other means of power generations that will see a reduction in power prices. These policies include carbon tax and emission reduction targets. Nevertheless, this study show that the carbon tax is more effective than the emission reduction target Considering climate change, generation expansion options based on non-renewable energy pathway appear to be less optimal. Therefore, the current set of energy and climate policies in Australia needs to be improved to focus on the long-term benefits of transitioning from the current stock of fossil fuel power plants to a clean power system. This will result in great potential for an affordable energy future that will be secured, reliable and clean, regardless of varying climatic conditions. Thus, the future low-carbon pathway, as well as combating climate change, lie in clean energy and a combination of innovative energy policies, which should be acceptable by the governments of all federating units in Australia.

There are some limitations in this study which future research could consider. First, the issue of over consumption of biomass for electricity generation can increase emissions, likewise exercise impact on biodiversity. This indeed is an important area of research that requires attention. Secondly, the inter-sectorial impact of emission reduction policies was not examined but should be considered in future studies. Third, changing the price of input fuels and cost of energy technologies in the model will yield results which differs from those obtained here. It will be interesting to vary the price and cost of input parameters to further examine the sensitivity of the model. This can be a form of data sensitivity analysis which will present more power plant expansion pathways. Fourth, future research can extend the policy scenario options and/or examine other policy pathways. Their results can be used to compare our modelling outcome. Finally, the current study used the LEAP model with the OSeMOSYS optimization extension to examine climate change impact on thermal and solar power plants. Future studies can use similar approach with available wind and hydropower data to model climate change impact on the electricity sector in Australia, or in other countries.

Chapter 6: Synthesis, Conclusion and Policy Implications

The previous four chapters have reviewed literature related to CV&C impacts on the energy system; estimated the influence of seasonal climatic and socioeconomic factors on electricity demand; modelled the dynamic interactions between energy policies and CV&C impacts on the energy system, and identified least-cost electricity generation technologies, as well as effective emission reduction policies under climate change scenarios in Australia. This chapter summarises the key findings of the thesis, identifies policy implications, discusses their relevance to the energy system, and provides some suggestions for future research.

6.1. Summary of Key Findings

The nature of the dynamic interactions between climate change and energy system, and their effects on economy and the environment remains a complex unresolved issue for researchers and policymakers today. The persistent increase in energy demand and socioeconomic dynamics such as population, leads to an increase in GHG emissions resulting in climate change. The energy system as a leading contributor to GHG emissions, is highly vulnerable to CV&C, as incurred damages extend beyond economic cost to increased environmental pollution. Therefore, studies focusing on energy system decarbonisation using energy policies that consider future climatic conditions would be of interests to researchers, energy companies and policymakers. It is on the above precedents that this thesis examined the interactions of a variety of energy and emission reduction policies which aim to address CV&C impact on the energy system and other economic sectors using Australia as a case study.

This thesis began to address the issue of CV&C impacts on the energy system by first undertaking detailed review of the literature, in a bid to identify patterns of CV&C impacts and existing research gaps. The review found scarce peer-reviewed publications focusing on Australia as compared to other developed countries. Again, it discovered quite few studies that examined the demand sectors and energy technologies. The review revealed a consistent decrease in building energy demand, and a decline in hydropower, thermal power plants and solar PV systems by the near- to mid-century. However, reviewed Australian based studies did not integrate supply side impacts with those of demand side while considering changes in socioeconomic factors.

More importantly, the complete energy system interactions with climate change and energy policy interventions are sparse in the published literature. Although, low carbon technologies have been identified as GHG mitigation technologies, it is still unclear how these alternative technologies would shape future energy system considering the climatic conditions. Finally, there is paucity of literature on technoeconomic and environmental implications of the CV&C impacts and future policy interventions.

Identified research gaps spotted by the literature review collectively set in motion this thesis in addressing the research problems. This involves the development of policy and climate change scenarios for future energy pathways using a simulation model. Before this can be achieved, it was important to estimate the influence of seasonal climatic and socioeconomic factors on electricity demand. This was estimated in the second paper using ARDL model and temperature projections from GCMs. The ARDL results show that the response of southern states to lower temperatures were higher than states in the northern regions of Australia (NT and QLD). Peak electricity demand during winter were attributed to heating demand across Australia, except QLD and NT. Whilst higher electricity demand were estimated during summer months in QLD and NT.

The simulation of future electricity demand under CV&C shows that Australia had an upward sloping climate-response functions which result in an increase in electricity demand due to increase in cooling demand rather than heating demand under all RCP scenarios. Higher monthly peak demand was projected during September in NSW; May in VIC (which changes after March); March and November in QLD; January and February in SA; July and August in WA; June, July, and August in TAS; and January, February, and December in NT. Although the changes in electricity demand varied across RCPs and time periods, the annual increase in electricity demand is projected for the states and territory in Australia. The chapter also consider policy uncertainties and examined interventions of energy efficiency, renewable energy target, price changes and economic growth. The results show that energy efficiency and RET significantly reduced future electricity demand despite global warming conditions. The chapter recommended an increased penetration of renewables and energy efficiency as relevant to decreasing climate-induced peak electricity demand.

The estimates from the ARDL model and temperature projections were used to develop scenario-based model using the LEAP modelling tool. The scenarios developed were BAU, low carbon economy based on either CCS or nuclear scenario, low grid renewable investment but with increased renewable penetration, and advance renewable economy where emission reduction targets are met by 2030, as well as clean energy technology dominating the energy system by 2050. In this chapter, the aim was to model the dynamic interactions between energy policies and CV&C impacts on the energy system and examine their technoeconomic implications. The analysis showed substantial impacts on energy demand, as well as impacts on power sector capacity expansion, investments, revenue generation, and associated direct and indirect emissions.

Under the BAU scenario, CV&C will result in an increase in energy demand by 72 PJ and 150 PJ in the residential and commercial sectors, respectively. The temperature induced increase enlarges the non-climate BAU demand, which will increase threefold before 2050. While under the non-climate BAU, there is an expansion of installed capacity to 81.8 GW generating 524.6 TWh. Due to CV&C impacts, power output declines by 59 TWh and 157 TWh in RCP 4.5 and RCP 8.5 climate scenarios respectively. This leads to an increase in generation costs by 10% from the base year, but a decrease in sales revenue by 8% and 21% in RCP 4.5 and RCP 8.5, respectively.

In the transport sector, alternative vehicles and fuels contributed to a decrease in primary energy demand, but a shift in demand to secondary fuels, such as electricity, which can be generated from a renewable source. Interregional trade of electricity commodity reveals that CV&C will result in increased demand and decreased power output in the NEM in Australia. The LRMC results reveal that lower investment in grid technologies, especially fossil fuel, and an increase in the capacity of renewable energy can potentially decrease wholesale and retail electricity prices. Cumulative cost-benefit analysis of the alternative scenarios compared to the BAU indicated that the energy efficiency policy in the LGRE scenario will result in an economic benefit of US$3.9 trillion by 2050, and the benefits increase to US$4.9 trillion in a higher renewable energy scenario. The chapter concludes that although energy demand and GHG emissions reduction policies may be expensive on the short-run, long-run benefits in terms of cost savings, emission reductions, and power sector management supersede the short-term costs.

The final chapter of this thesis explored the least-cost combination of electricity generation technology and identified effective emission reduction policies under climate change in Australia. The estimates from ARDL model and temperature projections from GCMs in chapter 3 and parameters from chapter 4 was used in an optimisation analysis using the OSeMOSYS which is integrated into the LEAP model. Policies explored include, base case which assumes no policy intervention, BC OPT, CT, CO2, RET and NEPP. The results show that the least combination technologies differ in their configuration across the country. However, BC OPT, RET and NEPP present least cost generation option for Australia energy system. The difference between the scenarios was that BC OPT had a 90-95% renewable electricity supply, while the RET and NEPP attained a 100% renewable supply by 2050, comprising solar, wind, and large-scale battery storage systems. Also, energy technologies in the BC OPT scenario were sensitive to temperature variations than RET and NEPP.

The carbon tax policy was identified as an effective policy compared to the current emission reduction target policy. This is because, carbon tax policies were found yielding economic benefits of about US$ 1.8 billion in installation cost, resource savings, and environmental externalities by 2050. Renewable dominated scenarios present the highest economic benefits in terms of policy intervention, and lower discount rates due to the penetration of renewables on the long run. In terms of social cost, the CT scenario approach was considered a better policy approach to emission reduction than CO2 scenario. However, sales revenue was higher in the RET scenario compared to other alternative scenarios. The study equally found that under climate change conditions, sales revenue for solar rooftops doubled in the RCP 4.5 and tripled in the RCP 8.5 scenarios.

The cost of generating electricity was observed to be the lowest in NEPP scenario, compared to other policy scenarios. Climatic conditions were also observed to inspire lower electricity production cost in the CT and CO2 scenarios, owing to how they switched with renewable options to meet rising demand, in a bid to address declining output from thermal power plants. Environmental results show that the current Australian government emission reduction target will not lead to reduction in GHG emissions from the electricity sector, rather, it will increase in cumulative emissions, which may double under climate change. The outcome of the three empirical studies revealed significant pathways to energy system decarbonisation considering climate change conditions. The implication of the outcome for policy planning are presented in the next section.

6.2. Policy Implications

Although the pathways show the possibility of energy and emission reduction before 2050, the IPCC 2050 milestone for renewable dominated energy system implies that the Australian government must reconsider its stand on future energy policies in the face of climate change. This is due to potential increase in energy demand courtesy of global warming, higher economic damages as a result of rising fuel expenditures and increasing GHG emission from fossil fuel dominated energy mix. The implications for the policy scenarios examined in this thesis are further discussed below.

6.2.1. Technological Implications

Changes in energy technologies has far-reaching implications on future energy system in response to climate change. First, the projected increase in demand considering CV&C will result in increased generation capacity as power companies begin to adjust in meeting growing electricity demand. The current stock of energy technologies in Australia mainly comprise of coal and gas power plants, hence the need for expansion of the current capacity to address climate induced demand. However, this thesis shows that Australia's future energy system which is highly dependent on fossil fuel supply will see power output from thermal power plant decline, owing to rising temperature. More disturbing is the issue of rising gas prices which has been one main cause of rising electricity prices in Australia. The increase in gas prices is due to the growth in liquified natural gas export to Asian market. With this export expanding, electricity prices are expected to further increase in the coming years if strategic policies are not put in place to address the issue.

Regarding interregional trading of electricity within the NEM, model results from Chapter 4 are in contrast to AEMO (Operator, 2016a) report which projects the NEM grid electricity supply to remain flat for the next 20 years. However, interregional demand results in chapter 4 consider two severe climatic conditions and reveal an increase in demand and decrease in power output in NEM states. Policymakers should consider these results and examine the possibility of expanding the grid's generation supply by increasing investments in renewable technologies and retiring ageing coal power plants with less efficient power production. The energy system is expected to transition from its current state due to LNG exports, which will pressure fossil fuel power plants and consumers, who may pay more for electricity and gas. Therefore, government policies should focus on improving the penetration of renewables to allow for an increased volume of LNG exports.

Non-climate sensitive sectors such as the industry sector has shown a decline in energy consumption due to Australia's shift towards a service-based economy. However, the rise in commodity prices may increase mining activities such as automation which may further increase energy consumption from the industry sector in the future. Policy option investigated in this study suggests the implementation of improved energy efficiency practices, such as improving ore and waste separation, high-pressure grading rolls in the mining sector, decreasing thermal losses from heating furnaces and encouraging the use of electric arc furnaces in the manufacturing sector, and providing incentives to increase biofuel use in the construction sector. In the transport sector, energy consumption substantially decreased through a combined policy option, which involved shifting 17% to 23% of passengers to public bus services in the seven Australian states, and increasing the penetration of alternative vehicles by 90%, such as EV, PHEV and HFCV, and fuel switching to biofuel in the road transport and aviation sector.

Although alternative transport technologies such as EV, PHEV and HFCV have lower tailpipe emissions, their real environmental impact mainly rely on local electricity generation process (Beer et al., 2009, Robledo et al., 2018, Staffell et al., 2019). Fuel switching to biofuels as a policy strategy presents an issue, as biofuel is not carbon neutral (Booth, 2018, DeCicco, 2018, DeCicco et al., 2016) and its use in the aviation sector is still at infancy (Bosch et al., 2017). Notwithstanding, the application of fuel switching, deeper penetration of alternative vehicles and modal shifting to public transport system will significantly diversify the energy mix and reduce the consumption of fossil fuel.

6.2.2. Economic Implications

The economic implication considers how CV&C impacts will affect power company's sales revenue and cost of generating electricity, and how policies can intervene under severe climate conditions. For sales revenue, reduction in revenue generation due to climate change is projected to be between 8-21% considering BAU scenario and the reduction goes higher across the alternative scenarios in chapter 4 and 5. However, scenarios with higher integration of renewables were observed to have an increase in revenue generation from electricity sales by 2050. This implies that revenue losses in the BAU and fossil fuel dominated scenarios considering global warming will be higher than in renewable dominated scenarios. Therefore, power sector investments should focus on renewable technologies to avoid reduction in revenue due to a decreased power supply as a result of climate change.

On electricity generation cost, Australian power companies may spend up to 46% more on fuel cost under BAU scenario and spend further 24% due to climate change. The energy modelling outcome of chapter 4 and 5 indicates that scenarios dominated by renewables had fuel cost savings of over 88% by 2050. This implies that IPCC recommendation for the global switching to renewables which share above 75% in the energy mix has the potential to significantly reduce power generation cost by 2050. The sensitivity analysis in chapter 4 and 5 also shows that higher investment in renewables will ensure an economy more resilient to changes in fuel prices and investment costs. Power sector investments are capital intensive and the model results show that companies can save on operational cost and increase sales revenue if they invest in renewable energy technologies.

Addressing rising energy prices have been an important issue to the Australian government. To examine how the scenarios will ensure low energy prices, the LRMC of electricity was estimated. The results from chapter 4 and chapter 5 both agree that a progressive scenario dominated by renewables is the only clear pathway for Australia to reduce its surging electricity prices under climate and non-climate change conditions. Also, the cost-benefit analysis reveals that deeper penetration of renewables widen the benefit gap, as policy initiatives aim at expanding renewable energy adoption, yield maximum benefits on the long run. Therefore, policymakers should consider increase adoption of renewables in the energy mix as not just a GHG mitigation measure, but an electricity price reduction strategy that is even more effective under climatic conditions.

6.2.3. Environmental Implications

The environmental analysis conducted in this thesis shows that the current government emission reduction target is not only inefficient in reducing GHG emissions, as the policy will further increase Australia's cumulative GHG emissions by 2050. In fact, carbon tax was observed to be effective in emission reduction compared to the emission reduction target. However, if global warming exceeds +2^{o}C, the optimisation model predicts a rapid switch to renewables as GHG emissions will become higher and power companies will have to make changes in their electricity generation portfolio. In chapter 4, the model shows that lower investment in grid generation technologies with higher penetration of renewables has higher emission reduction potential. Similarly, results from chapter 5 show that RET and NEPP made up of massive investment in energy efficiency and renewables had the highest emission reduction potential. The two modelling results provide a case for renewable energy in Australia, as lower demand for energy and increased electricity generation from renewable energy source presents a win-win scenario for the country.

Further, the results of cumulative GHG savings reveal that the adoption of CCS technologies will result in cumulative GHG savings that is 3 times higher than a 100% renewable scenario. Examining the global warming potential and indirect GHG emissions, climate-sensitive demand side technologies such as water heating, space conditioning and appliance operations will significantly contribute to global warming by 2050. However, global warming potential are three times lower when the technologies are powered from a renewable energy source. Finally, the decomposition analysis in chapter 4 demonstrates that emission and energy intensity effects were significant in reducing the accumulation of GHGs. However, activity effects will increase GHGs in the alternative scenarios—except in renewable energy scenario, in which the activity effect decreases emission levels by 2050. This implies that the introduction of improved energy efficiency policies and alternative fuel/technology options will be a more effective GHGs mitigation policy.

6.3. Relevance of the Findings

What do Australian energy policymakers and power companies derive from this research? How can these data be applied to foster sustainability and resilience for the country's energy system and similar systems across the globe?

First, to ensure a complete energy system decarbonisation as proposed by the IPCC, this thesis presents effective policy pathways that can be adopted by the Australian government. This thesis clearly highlights the need to switch to renewables as it presents economic benefits and effective GHG mitigation. Although the carbon tax scenario showed higher economic benefit and emissions savings potential compared to the emission reduction policy based on the ERF alone, a tax is a major political liability. This is because the tax policy as modelled in this study may induce large transfer of income from power companies to the government. If the power companies pay for abatement to reduce its emissions, they will still have to pay for the remaining emissions if there is a cap on GHG emissions as in the ERT scenario. This will result in power companies paying taxes that are larger than the cost of abatement which may further complicate the current political debate on emission reduction from energy intensive industries in Australia.

A solution can be the replacement of the current emission reduction policy (based on the ERF) with a hybrid policy which combines the advantages of a carbon tax and permit as short-term policies. This suggestion is similar to the defunct Australian Carbon Pollution Reduction Scheme where a cap-and-trade was the main structure with a price limit on emission permit in its inception and unlimited acceptance of emission credits (Australia, 2010a, Nielson, 2010). In the hybrid policy, the power companies will never pay more than the cost of abatement and there will be a reduced transfer of income as trading will be between industries with the government providing oversight. This thesis can be a guideline on how the policy can be systematically introduced in the energy sector with gas power plants fitted with CCS technologies while retiring coal power plants. On the long-run, the energy system should be based on renewables and battery storage systems as shown in this thesis to ensure a complete decarbonisation before 2050.

Secondly, while the data shows emissions from electricity production as a significant emitter compared to other sectors, technological changes will play an important role in GHG mitigation. This can be seen in the results for indirect GHG emissions from the demand side which shows that improvement in space conditioning technologies and appliances in the residential and commercial sector has the potential to significantly reduce emissions before 2050. Also, deeper penetration of alternative technologies and fuels in the transport sector can contribute towards decarbonisation of non-climate sensitive sectors. This thesis could serve as a guide on the changes in technology options and the process or period when capacity for a particular technology can be upgraded. This is important for power companies that may require information on how future electricity demand will look like from a wholistic view. Also, tracking the progress of other energy intensive sectors such as transport sector reveals the importance of increased penetration of alternative fuels and vehicles.

Thirdly, data on sales revenue and electricity generation cost is not only important for power companies, but electricity market. This thesis shows how these cost factors will be affected considering CV&C in future and how power companies can respond in order to maximise sales revenue. Responding to the rise in electricity prices through building new fossil fuel power plants in Australia has been shown to be unsustainable, higher economic cost and increase GHG emission in the future. The alternative means is a renewable based system which has the potentials to reduce electricity prices and generation cost, while increasing revenues and emission savings. This means that power companies will not only benefit from increase return on investment and reduced operation cost, but also make meaningful contributions in efforts to reduce energy sector GHG emissions considering climate change.

Finally, as this thesis presents the outcome resulting from interactions of policies and climate change through scenario analysis, policymakers can combine several pathways for a sustainable and resilient energy system. This is because managing GHG emissions and increasing climate-induced demand will require the application of strategic policy options to cushion CV&C impacts. Therefore, the results of this thesis will be of significant interest to policymakers who intends to design efficient GHG mitigation policies for the energy system that are effective under climate change conditions.

6.4. Directions for Future Research

This thesis focused on the impacts of CV&C on the energy system and examined how future energy policies can help cushion the impact, thereby, efficiently reducing GHG emissions. However, studies included in this thesis are not without limitations, as a number of questions could still be investigated. For instance: What is the level of consumer acceptance of alternative technologies considering future cost and willingness to pay? What is the cost implication of improving transmission and distribution facilities to accommodate electricity generation expansion by 2050 under climate and non-climate scenarios? Future research could also take advantage of the LEAP model flexibility to account for future changes in hydropower and wind energy systems, as this was not considered in the current study.

Although this thesis focuses on Australian energy system, the rising international pressure to decarbonise the energy sector presents the following questions: How does the modelling outcome of this thesis relates to the energy system of other countries? Are there specific energy system characteristics that are associated with higher or lower emissions profiles? What are the implications for land use considering biofuel policies and how will land availability affect the expansion of electricity generation technologies in the future? Finally, the scenarios examined in this thesis are not exhaustible as other policy options can be explored and pathways compared with modelling outcomes found in this thesis.

There is much more to be explored on the topic of CV&C impacts on the energy system. For example, the differences between daytime and night-time temperatures, and between urban and regional areas due to urban heat island were not considered in this study These future research areas could be embarked to provide for some shortcomings of this study, as concern scaling up broader efficiency for the energy sector across the globe. Just as stated in chapter 1, “This thesis begins to explore pathways for energy system transition under climate and policy scenarios to ensure the sustainability and resilience of the energy system”. Therefore, its outcome is not the culmination of policy options aimed at cushioning impacts of CV&C on the energy system, and definitely does not halt my research in this area.

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Appendix 1: Preferred Reporting Items for Systematic Reviews and Meta-Analyses (PRISMA) Checklist

Table A1.1: PRISMA Checklist

Section/topic	#	Checklist item	Reported on page #
TITLE			
Title	1	Identify the report as a systematic review, meta-analysis, or both.	1
ABSTRACT			
Structured summary	2	Provide a structured summary including, as applicable: background; objectives; data sources; study eligibility criteria, participants, and interventions; study appraisal and synthesis methods; results; limitations; conclusions and implications of key findings; systematic review registration number.	3
INTRODUCTION			
Rationale	3	Describe the rationale for the review in the context of what is already known.	3-6
Objectives	4	Provide an explicit statement of questions being addressed with reference to participants, interventions, comparisons, outcomes, and study design (PICOS).	5-6
METHODS			
Protocol and registration	5	Indicate if a review protocol exists, if and where it can be accessed (e.g., Web address), and, if available, provide registration information including registration number.	6-7
Eligibility criteria	6	Specify study characteristics (e.g., PICOS, length of follow-up) and report characteristics (e.g., years considered, language, publication status) used as criteria for eligibility, giving rationale.	7-8
Information sources	7	Describe all information sources (e.g., databases with dates of coverage, contact with study authors to identify additional studies) in the search and date last searched.	7-8
Search	8	Present full electronic search strategy for at least one database, including any limits used, such that it could be repeated.	8 and Table 2.1
Study selection	9	State the process for selecting studies (i.e., screening, eligibility, included in systematic review, and, if applicable, included in the meta-analysis).	8-9

Data collection process	10	Describe method of data extraction from reports (e.g., piloted forms, independently, in duplicate) and any processes for obtaining and confirming data from investigators.	9-11
Data items	11	List and define all variables for which data were sought (e.g., PICOS, funding sources) and any assumptions and simplifications made.	11
Risk of bias in individual studies	12	Describe methods used for assessing risk of bias of individual studies (including specification of whether this was done at the study or outcome level), and how this information is to be used in any data synthesis.	11
Summary measures	13	State the principal summary measures (e.g., risk ratio, difference in means).	N/A
Synthesis of results	14	Describe the methods of handling data and combining results of studies, if done, including measures of consistency (e.g., I^2) for each meta-analysis.	N/A

Section/topic	#	Checklist item	Reported on page #
Risk of bias across studies	15	Specify any assessment of risk of bias that may affect the cumulative evidence (e.g., publication bias, selective reporting within studies).	N/A
Additional analyses	16	Describe methods of additional analyses (e.g., sensitivity or subgroup analyses, meta-regression), if done, indicating which were pre-specified.	N/A
RESULTS			
Study selection	17	Give numbers of studies screened, assessed for eligibility, and included in the review, with reasons for exclusions at each stage, ideally with a flow diagram.	11 and Figure 2.2
Study characteristics	18	For each study, present characteristics for which data were extracted (e.g., study size, PICOS, follow-up period) and provide the citations.	13-25 and Table S2d
Risk of bias within studies	19	Present data on risk of bias of each study and, if available, any outcome level assessment (see item 12).	N/A
Results of individual studies	20	For all outcomes considered (benefits or harms), present, for each study: (a) simple summary data for each intervention group (b) effect estimates and confidence intervals, ideally with a forest plot.	25-36 and Table 2.2
Synthesis of results	21	Present results of each meta-analysis done, including confidence intervals and measures of consistency.	N/A
Risk of bias across studies	22	Present results of any assessment of risk of bias across studies (see Item 15).	N/A
Additional analysis	23	Give results of additional analyses, if done (e.g., sensitivity or subgroup analyses, meta-regression [see Item 16]).	N/A

DISCUSSION			
Summary of evidence	24	Summarize the main findings including the strength of evidence for each main outcome; consider their relevance to key groups (e.g., healthcare providers, users, and policy makers).	36-42
Limitations	25	Discuss limitations at study and outcome level (e.g., risk of bias), and at review-level (e.g., incomplete retrieval of identified research, reporting bias).	42-43
Conclusions	26	Provide a general interpretation of the results in the context of other evidence, and implications for future research.	43-45
FUNDING			
Funding	27	Describe sources of funding for the systematic review and other support (e.g., supply of data); role of funders for the systematic review.	N/A

From: Moher D, Liberati A, Tetzlaff J, Altman DG, The PRISMA Group (2009). Preferred Reporting Items for Systematic Reviews and Meta-Analyses: The PRISMA Statement. PLoS Med 6(7): e1000097. doi:10.1371/journal.pmed1000097

For more information, visit: **www.prisma-statement.org**.

Appendix 2: Scorecard and Articles Included for the Review

Star screening approach using a scorecard

As stated in in section 2.3 in the main manuscript, the score card and star rating follow the studies by Porter et al. (2014), Bonjean Stanton et al. (2016). The scorecard shown in Table S2a was used to assess studies based on star screening. The score card is defined by the attributes which consist of the study approach (SA), methodology (MA), results and analysis (RA) and policy implication (PI). The star rating are as follows:

- 5-star article includes all the attributes listed in the score card
- 4-star includes the attributes of a 5-star article except MD2, MD3, and RA2
- 3-star includes all the attributes of a 4-star article except MD4, MD5, and RA4
- Other papers with lower star rating (a total of 166 articles as shown in Figure 2 in the main manuscript) were excluded from the review

Table A2.1: Scorecard used for screening

Attributes	Score card
	Study approach
SA 1	The study approach is appropriate for the scale of impact assessment for the region, energy source or energy technology.
SA 2	An appropriate balance between methods applied and results. i.e. the article does not only describe the model used in the paper in detail but also explains the results
Methodology	
MD 1	The methodology applied are properly outlined
MD 2	The methodology is properly described to allow study replication in a different location
MD 3	The methodology explains why a climate model, impact assessment model and study location were selected
MD 4	The methodology applied more than one climate model to develop an envelope of climate data /uses ensemble of climate data "…the use of multiple models in climate change research is to cover different sources of uncertainties…" from page 1 in Wilcke and Bärring (2016)
MD 5	The methodology applied more than one climate change scenario to forecast different conditions Using climate change scenarios is an important step towards adaptation planning Dessai et al. (2005), Santoso et al. (2008)
MD 6	The methodology assessed the impact of CV&C on the near-, mid- and end-century.
MD 7	The climate model was ruinously tested before applied in the study and the study provides information on the calibration and validation of the climate/impact model

	"…Climate impact and adaptation assessments should incorporate the following steps: selecting the most appropriate climate and socio-economic scenarios; validation and calibration of models…" from page 55 in McMichael et al. (2001)
MD 8	The methodology assessed the annual and seasonal changes or inter-seasonal variations
MD 9	The impact model used has been widely applied and tested in the literature
Results and analysis	
RA 1	The results are stated clearly in detail, consistent and addresses the research questions presented
RA 2	The results were adequately analysed and information concerning limitations and uncertainties associated with the model were stated
RA 3	The study identified the use of its results for planning
RA 4	The results were compared to previous studies not authored by the same author(s)
Policy Implication	
PI 1	The study presented implications for policymaking

Table A2.2: Articles and results used for quantitative study (pattern of impacts of CV&C)

Note: #s = number of results by states; #r = number of results by regions; # = number of results by country

#	Article reference	Energy Demand			Energy Supply							Electricity Networks
		Residential	Commercial	Building	hydropower	Bioenergy	Wind energy	Thermal electricity	Solar photovoltaic	Wave energy	Ground source heat pump	Transmission and distribution
1.	Amato, A.D., Ruth, M., Kirshen, P., Horwitz, J., 2005. Regional Energy Demand Responses To Climate Change: Methodology And Application To The Commonwealth Of Massachusetts. Climatic Change 71, 175-201.	1	1									
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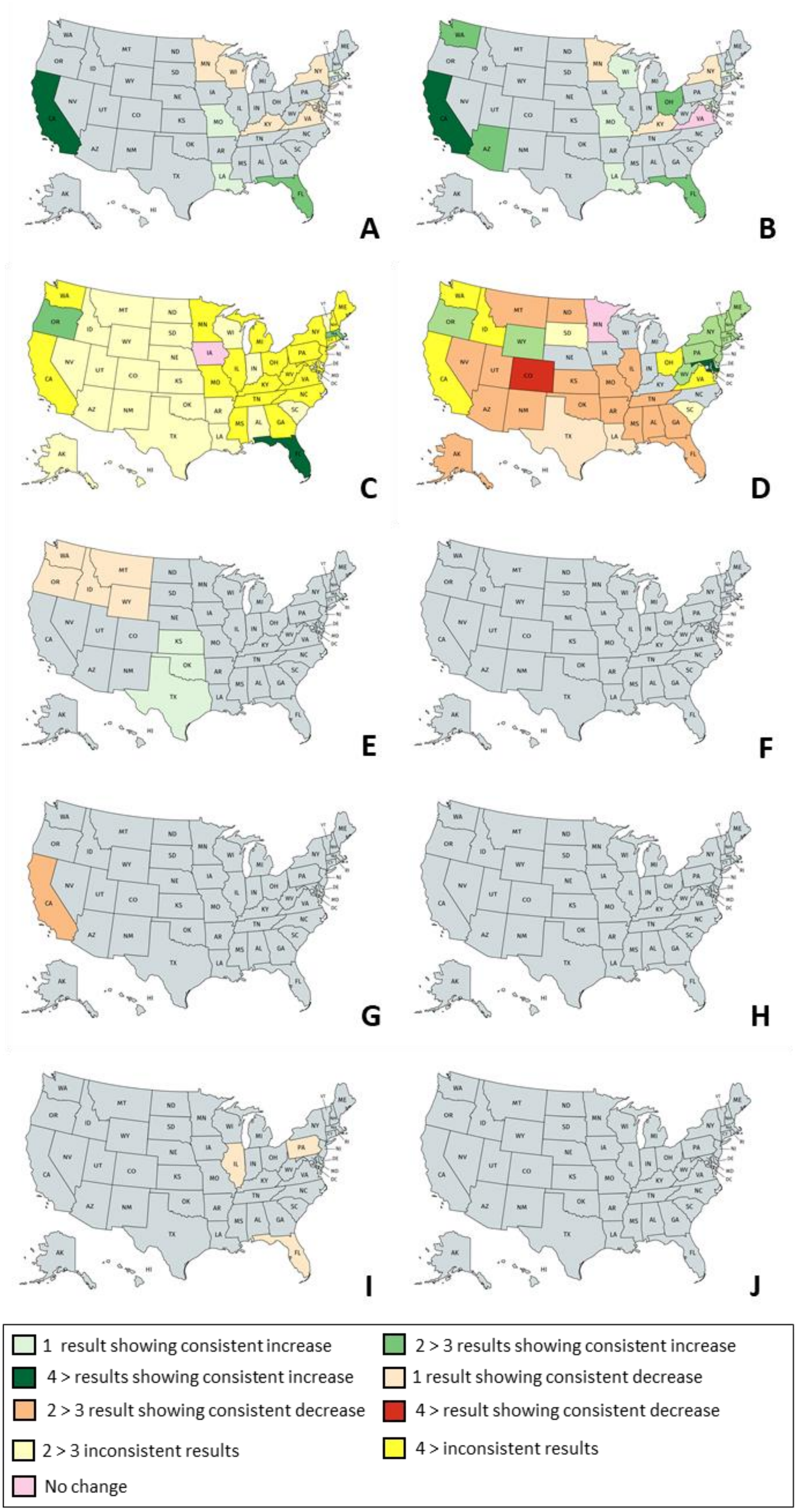

Figure A2.1: Annual patterns of impacts of CV&C-ES for NC-MC in the USA (A: Residential, B: commercial, C: economy, D: hydro, E: wind, F: thermal, G: solar, H: wave, I: ground water heat pump, J: T&D).

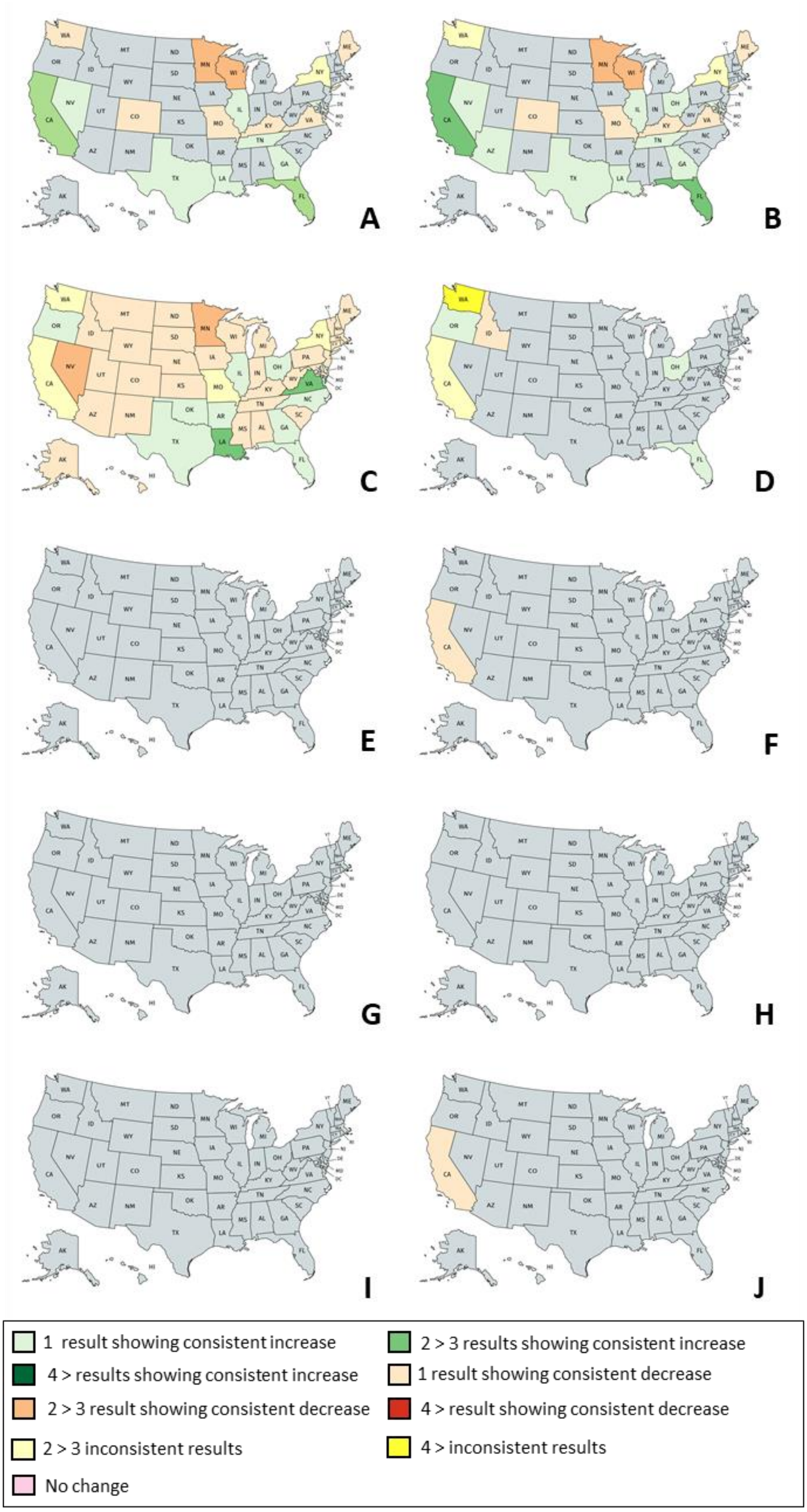

Figure A2.2: Annual patterns of impacts of CV&C-ES for EC in the USA (A: Residential, B: commercial, C: economy, D: hydro, E: wind, F: thermal, G: solar, H: wave, I: ground water heat pump, J: T&D).

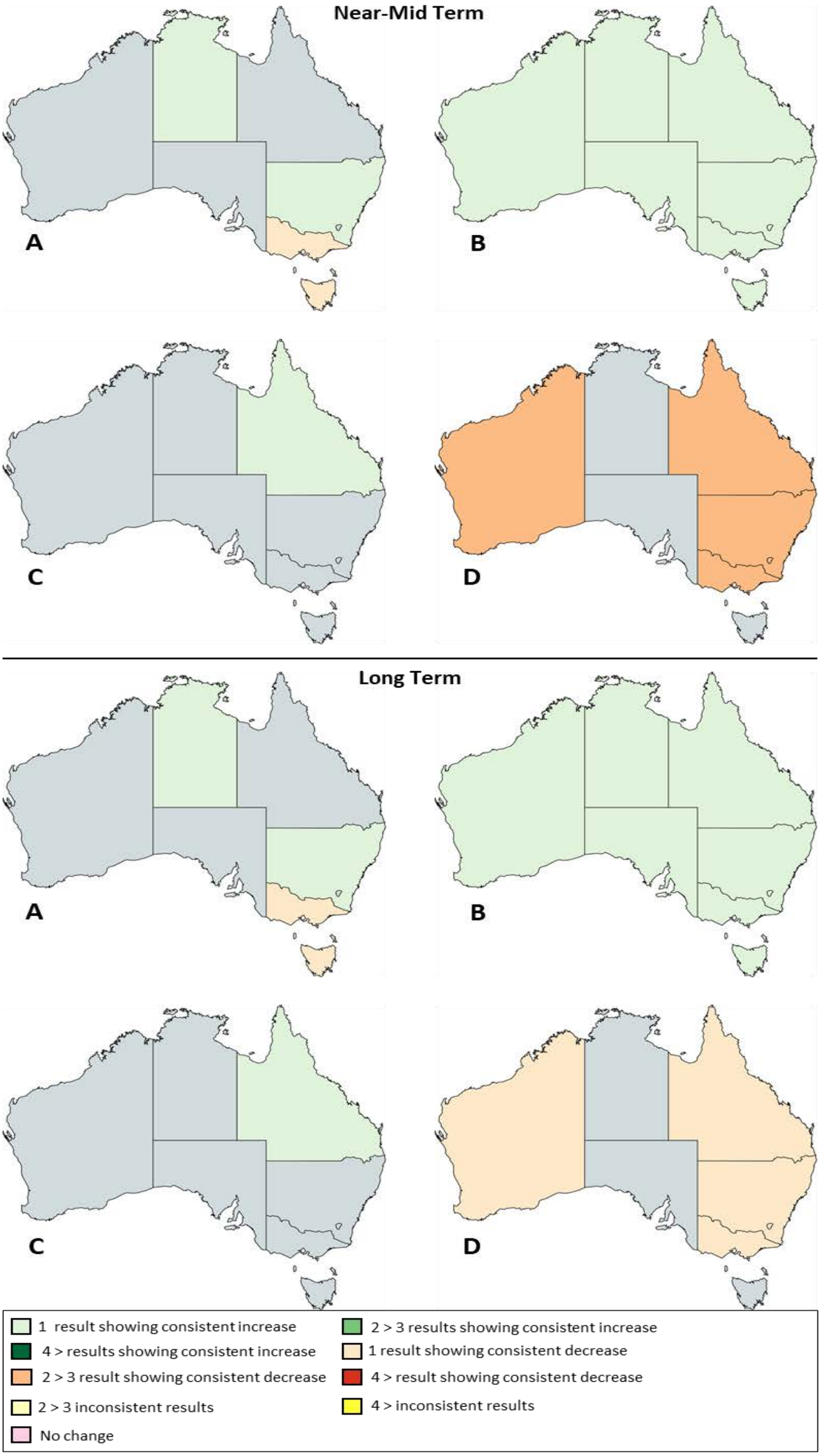

Figure A2.3: Annual patterns of impacts of CV&C-ES for Australia (A: Residential, B: commercial, C: solar and D: T&D).

Appendix 4: Locations of weather states and results of unit root test, bounds test and plots of CUSUM and CUSUMSQ

Table A4.1: Location of weather stations

State	Weather Station	Station Number
New South Wales	Sydney Airport AMO	066037
Victoria	Melbourne Airport VIC	086282
Queensland	University of Queensland Gatton QLD	040082
South Australia	Adelaide Airport SA	023034
Western Australia	Perth Airport WA	009021
Tasmania	Hobart (Ellerslie Road) TAS	094029
Northern Territory	Darwin Airport NT	014015

Table A4.2: Results of the unit root test

State	Variable	ADF				KPSS			
		Level		First Difference		Level		First Difference	
		No Trend	Trend	No Trend	Trend	No Trend	Trend	No Trend	Trend
New South Wales	*LogEL*	-1.71	-1.76	-4.72***	-1680***	0.28***	0.21	0.13***	0.08***
	LogGSP	1.12	-0.57	-2.63**	-2.78	0.89	0.11***	0.15***	0.14**
	POP	-1.38	-3.63**	-5.43***	-5.37***	0.50*	0.07***	0.12***	0.07***
	PR	-7.07***	-7.39***	-7.59***	-7.53***	0.44**	0.15***	0.17***	0.17***
	CDD	-2.85**	-3.72**	-4.28***	-4.18**	0.18***	0.04***	0.06***	0.04***
	HDD	-7.62***	-7.55***	-7.52***	-7.44***	0.07***	0.07***	0.14***	0.12***
Victoria	*LogEL*	0.41	0.26	-6.16***	-7.23***	0.56	0.54	0.53**	0.10***
	LogGSP	-1.19	-1.34	-3.23**	-3.14**	1.88	0.46	0.42**	0.06***
	POP	-2.20	-3.21**	-4.87***	-4.90***	1.51	0.05***	0.17***	0.09***
	PR	-3.95***	-4.12***	-11.32***	-11.30***	0.42**	0.06***	0.13***	0.10***
	CDD	-3.77***	-3.90**	-6.01***	-6.00***	0.04***	0.02***	0.11***	0.09***
	HDD	-3.87***	-4.51***	-14.01***	-13.98***	0.02***	0.01***	0.06***	0.03***
Queensland	*LogEL*	-2.27	-2.18	-2.99**	-3.00*	1.39	0.43	0.14***	0.13***
	LogGSP	-1.76	-0.97	-2.32	-2.82	1.87	0.44	0.42**	0.06***
	POP	-2.04	-2.73	-9.39***	-9.57***	0.52**	0.36	0.35***	0.14***
	PR	-6.73***	-10.87***	-11.78***	-11.76***	0.52**	0.15***	0.32***	0.16**
	CDD	-2.92**	-2.90	-15.92***	-15.88***	0.01***	0.01***	0.08***	0.04***
	HDD	-3.30**	-3.31***	-21.00***	-20.95***	0.01***	0.01***	0.04***	0.03***
South Australia	*LogEL*	-1.06	-1.42	-9.06***	-9.43***	0.74	0.63	0.12***	0.08***
	LogGSP	-1.75	-1.82	-2.97**	-3.32**	1.88	0.36	0.21***	0.05***
	POP	-1.42	-3.52**	-4.90***	-4.79***	1.11	0.09***	0.34***	0.20**
	PR	-2.06	-2.38	-8.01***	-8.09***	0.37**	0.10***	0.34***	0.29**
	CDD	-4.13***	-4.13***	-5.76***	-5.75***	0.02***	0.02***	0.10***	0.05***
	HDD	-3.90***	-4.91***	-10.91***	-10.90***	0.04***	0.01***	0.02***	0.01***
Western Australian	*LogEL*	-1.53	-1.41	-5.95***	-6.07***	1.60	0.50	0.07***	0.06***
	LogGSP	-0.73	-2.34	-1.54	-1.59	1.31	0.14**	0.12***	0.08***
	POP	-0.97	-3.28**	-2.65**	-2.33	1.29	0.27	0.63**	0.14**
	PR	-4.40***	-4.42***	-6.90***	-6.87***	0.10***	0.06***	0.12***	0.12***
	CDD	-3.19**	-3.06	-12.25***	-12.31***	0.02***	0.02***	0.07***	0.06***
	HDD	-2.19	-1.71	-11.23***	-11.36***	0.04***	0.04***	0.04***	0.03***
Tasmania	*LogEL*	-0.88	-2.99	-4.69***	-4.89***	0.36	0.02***	0.15***	0.09***
	LogGSP	-1.55	-2.49	-1.80	-1.77	1.20	0.27	0.30***	0.14***
	POP	-0.64	0.79	0.41	0.37	0.27***	0.17**	0.28***	0.13**
	PR	-5.51***	-5.60***	-5.53***	-5.53***	0.23***	0.14**	0.16***	0.16**
	CDD	-2.09	-2.01	-5.74***	-5.71***	0.04***	0.05***	0.14***	0.11***
	HDD	-2.43	-2.54	-5.28***	-5.27***	0.03***	0.01***	0.23***	0.12***
Northern Territory	*LogEL*	-1.88	-1.79	-5.56***	-5.59***	0.39**	0.30	0.16***	0.06***
	LogGSP	-1.00	-2.00	-19.08***	-19.05***	1.99	0.22	0.08***	0.08***
	POP	-0.84	-2.31	-19.13***	-19.10***	2.21	0.20**	0.07***	0.07***
	PR	-8.29***	-9.62***	-13.21***	-13.20***	1.36	0.33	0.29***	0.18**
	CDD	-1.32	-1.19	-11.97***	-11.98***	0.50**	0.26	0.09***	0.07***
	HDD	-9.55***	-9.58***	-11.07***	-11.06***	0.24***	0.14**	0.28***	0.27**

Notes: *** indicates significance at the 1% level, ** indicates significance at the 5% level, and * indicates significance at the 10% level. *LogEL* is the log of electricity demand, *LogGSP* is the log of gross state product, *PR* is electricity price, *POP* is population, *CDD* is cooling degree days, and *HDD* is heating degree days. The ADF test considers the null hypothesis of a unit root against the alternative hypothesis of no unit root for the series. The null hypothesis is rejected when the computed p-value is lower than the 0.05 significance level; the alternative hypothesis is then accepted. The KPSS test considers the null hypothesis of stationarity around a deterministic trend against the alternative of a unit root. The null hypothesis is accepted when the computed p-value is greater than the 0.05 significance level; the alternative hypothesis of a unit root is then rejected. The combination of the ADF test and KPSS test intends to reduce the incidence of high Type 1 errors (i.e. supporting the alternative hypothesis when the null is true) when deciding about the stationarity of the series.

Table A4.3: Results of the bounds test

State	Seasons	Model/Lags	F-statistics	Decision
New South Wales	Summer	ARDL (1, 1, 1, 1, 0, 0)	63.33***	Cointegration
	Autumn	ARDL (3, 0, 1, 3, 0, 1)	10.19***	Cointegration
	Winter	ARDL (2, 1, 1, 0, 0, 2)	14.56***	Cointegration
	Spring	ARDL (3, 3, 1, 2, 3, 2)	56.02***	Cointegration
Victoria	Summer	ARDL (4, 1, 5, 4, 0, 0)	16.64***	Cointegration
	Autumn	ARDL (1, 0, 1, 0, 1, 1)	88.30***	Cointegration
	Winter	ARDL (1, 0, 0, 0, 0, 0)	49.68***	Cointegration
	Spring	ARDL (2, 0, 3, 0, 3, 4)	23.83***	Cointegration
Queensland	Summer	ARDL (1, 1, 1, 0, 0, 0)	41.17***	Cointegration
	Autumn	ARDL (1, 0, 5, 3, 5, 1)	67.45***	Cointegration
	Winter	ARDL (3, 0, 0, 0, 0, 0)	13.878**	Cointegration
	Spring	ARDL (3, 4, 3, 4, 4, 4)	14.89***	Cointegration
South Australia	Summer	ARDL (2, 1, 0, 0, 2, 0)	23.01***	Cointegration
	Autumn	ARDL (2, 2, 1, 0, 0, 1)	39.36***	Cointegration
	Winter	ARDL (2, 1, 0, 2, 2, 2)	7.18***	Cointegration
	Spring	ARDL (1, 0, 1, 1, 0, 2)	28.01***	Cointegration
Western Australia	Summer	ARDL (1, 1, 0, 0, 0, 1)	59.51***	Cointegration
	Autumn	ARDL (1, 0, 0, 1, 1, 1)	41.37***	Cointegration
	Winter	ARDL (1, 0, 0, 0, 0, 0)	55.69***	Cointegration
	Spring	ARDL (1, 1, 1, 0, 0, 0)	23.73***	Cointegration
Tasmania	Summer	ARDL (1, 1, 0, 1, 0, 1)	20.80***	Cointegration
	Autumn	ARDL (1, 0, 0, 0, 0, 1)	18.80***	Cointegration
	Winter	ARDL (1, 0, 0, 0, 0, 0)	25.19***	Cointegration
	Spring	ARDL (1, 0, 0, 0, 0, 0)	26.79***	Cointegration
Northern Territory	Summer	ARDL (3, 2, 7, 0, 0, 0)	15.88***	Cointegration
	Autumn	ARDL (2, 2, 0, 0, 0, 0)	15.21***	Cointegration
	Winter	ARDL (2, 1, 0, 0, 1, 0)	16.30***	Cointegration
	Spring	ARDL (2, 0, 0, 0, 0, 0)	25.78***	Cointegration

Notes: The relevant critical value bounds are available in Table C1 (iii) Case III (with an unrestricted intercept with no trend; the number of repressors [*k*] = 5) in Pesaran et al. (2001, page 300). *** indicates significance at the 1% level.

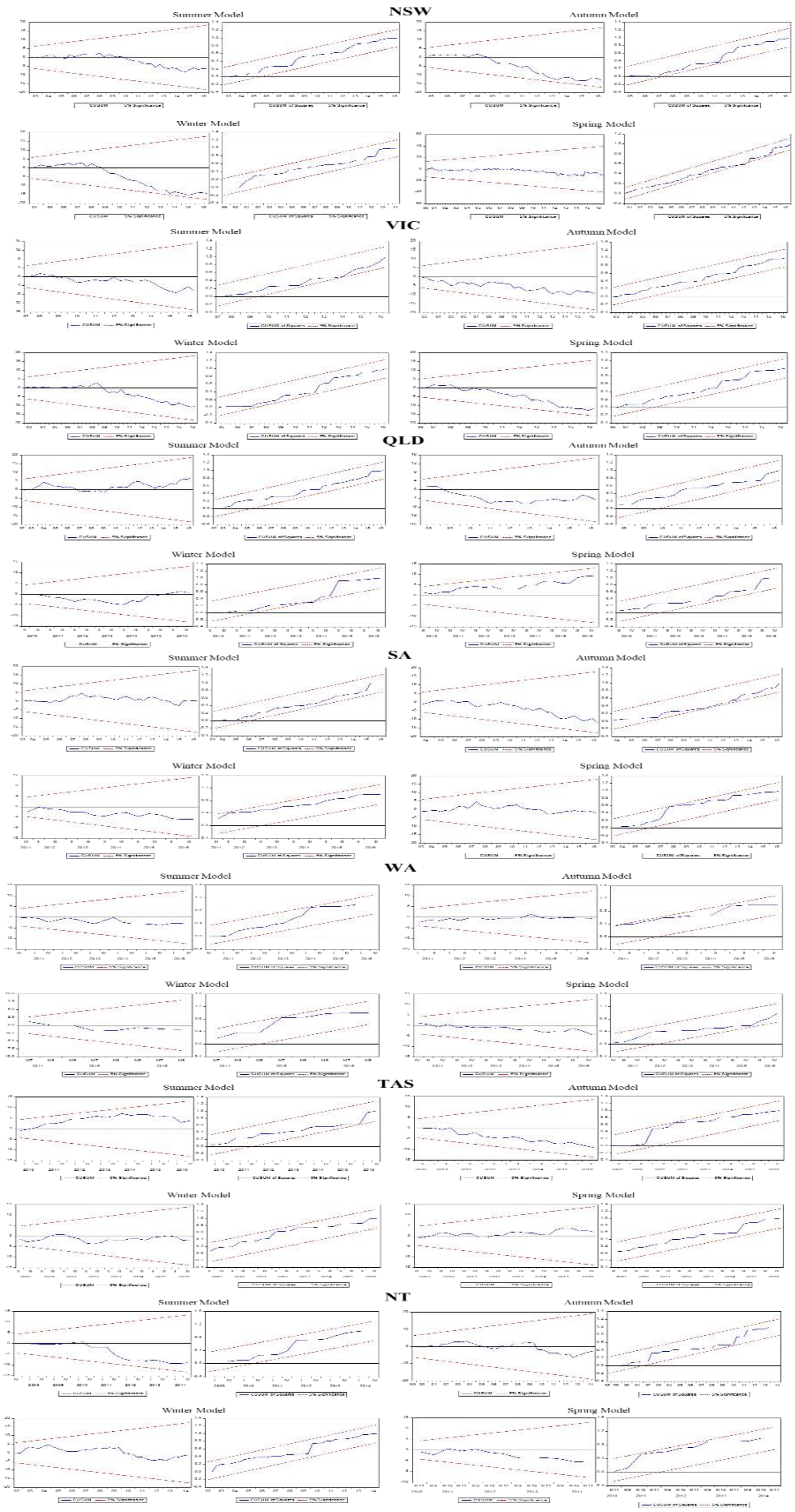

Figure A4.1: Plots of CUSUM and CUSUMSQ

Appendix 5: Forecast accuracy results

Table A5.1: The model's accuracy for different combinations of variables*

	MAPE	Standard deviation
M	2.56	2.22
ARDL_Full	0.81	0.57
ARDL_Climate	1.17	0.83
ARDL_Socioeco	1.29	1.01
MLR_Full	1.58	1.12

*Notes: *M* is the computed demand based on Equation 9; ARDL_Full is the ARDL model with complete variables (GSP, population, price, CDD, and HDD); ARDL_Climate is the ARDL model with climate variables only (CDD and HDD); ARDL_Socioeco is the ARDL model with socio-economic variables only (GSP, population, and price); and MLR_Full is the multiple linear regression model with complete variables.

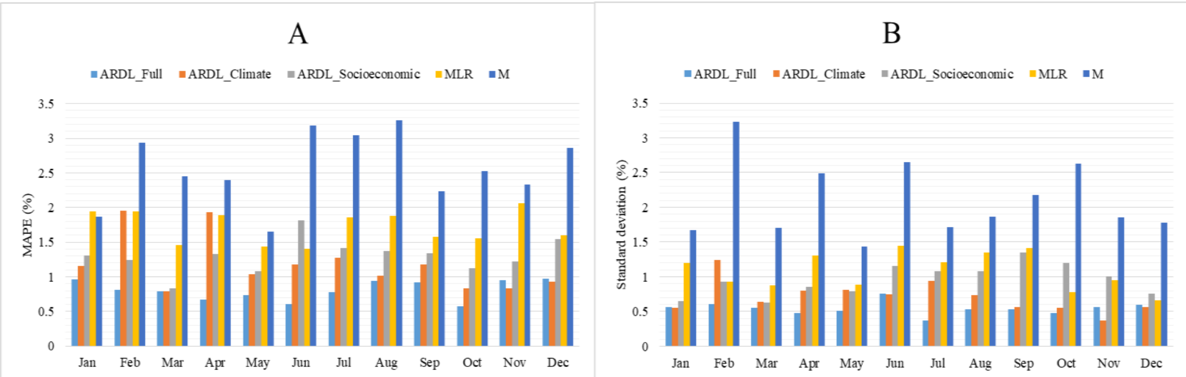

Figure A5.1: The model's accuracy: monthly and yearly MAPE for the combination of ARDL and MLR models from 1999 to 2010 (A) and standard deviation (B)

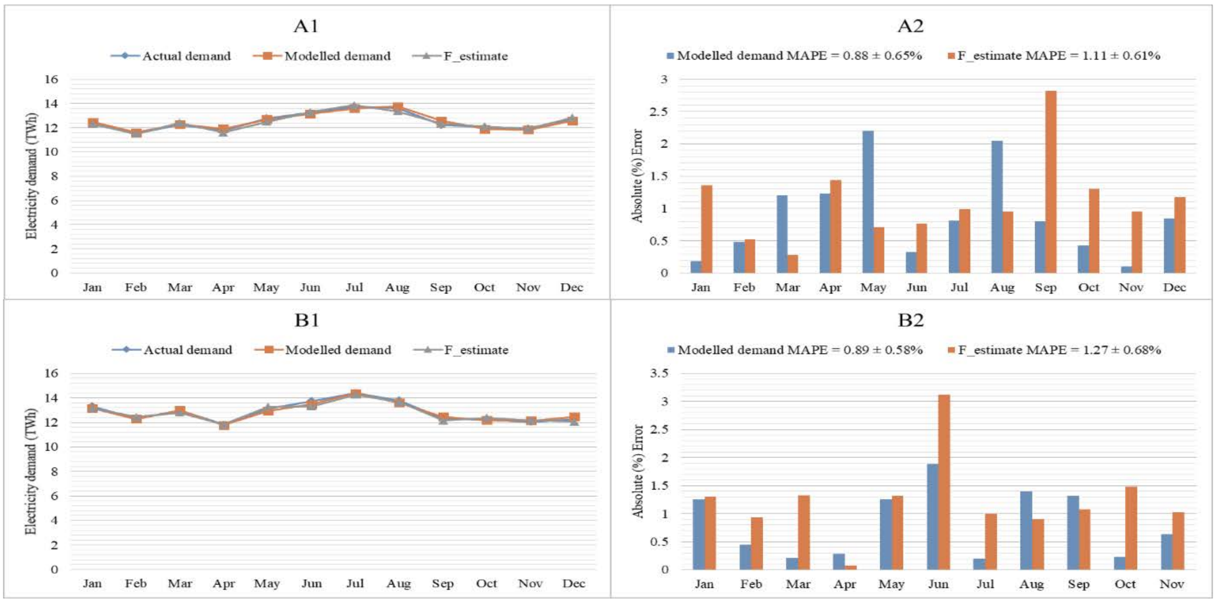

Figure A5.2: Forecast accuracy: comparisons between actual, modelled, and corrected *M* forecasts for 2005 (A1 and A2) and 2010 (B1 and B2)

Appendix 6: Projected CDD and HDD, monthly peak demand and percentage changes in electricity demand

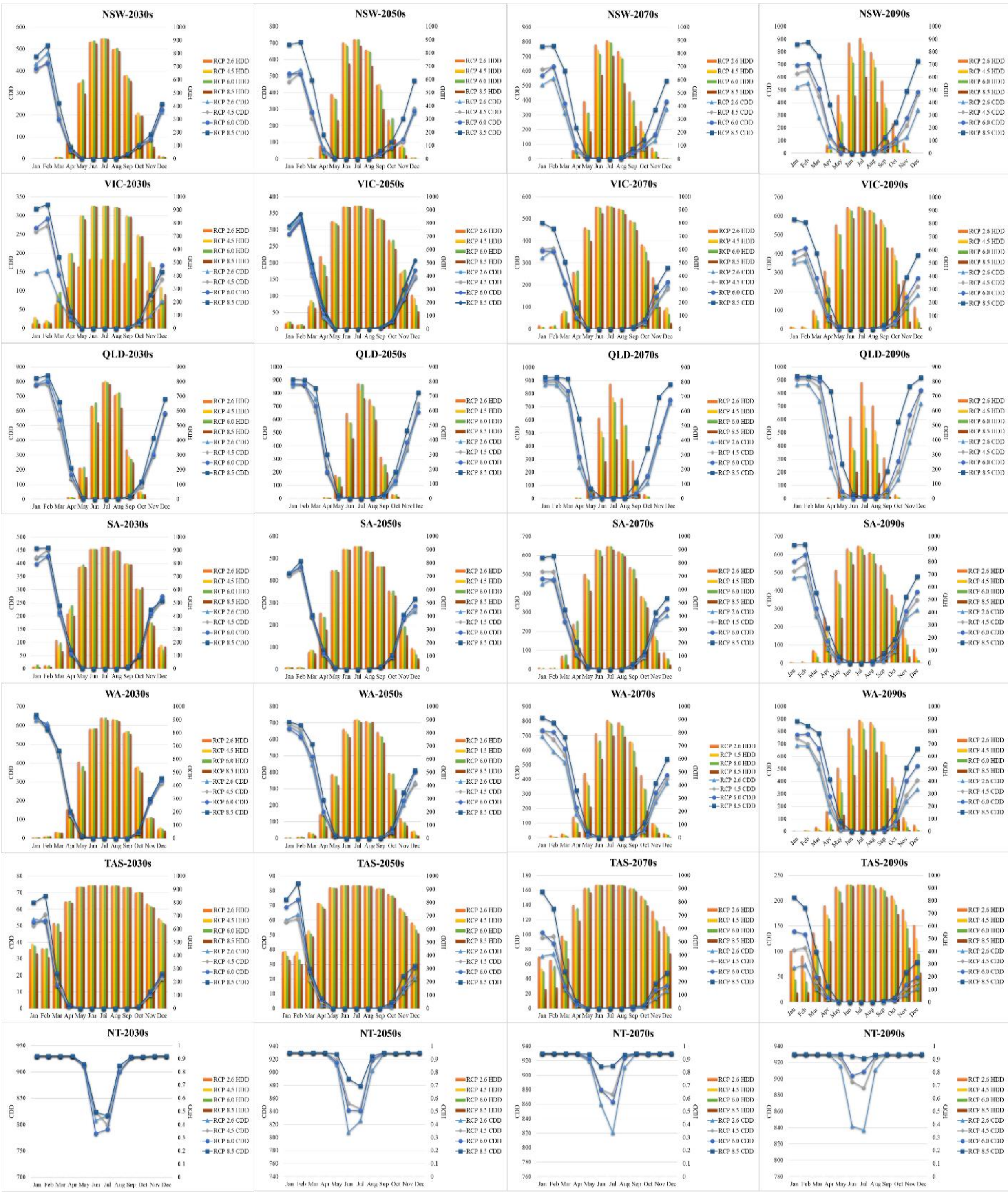

Figure A6.1: Future CDDs and HDDs for the 2030s (2016–2045), 2050s (2036–2065), 2070s (2056–2085), and 2090s (2075–2104) using the IPCC RCPs

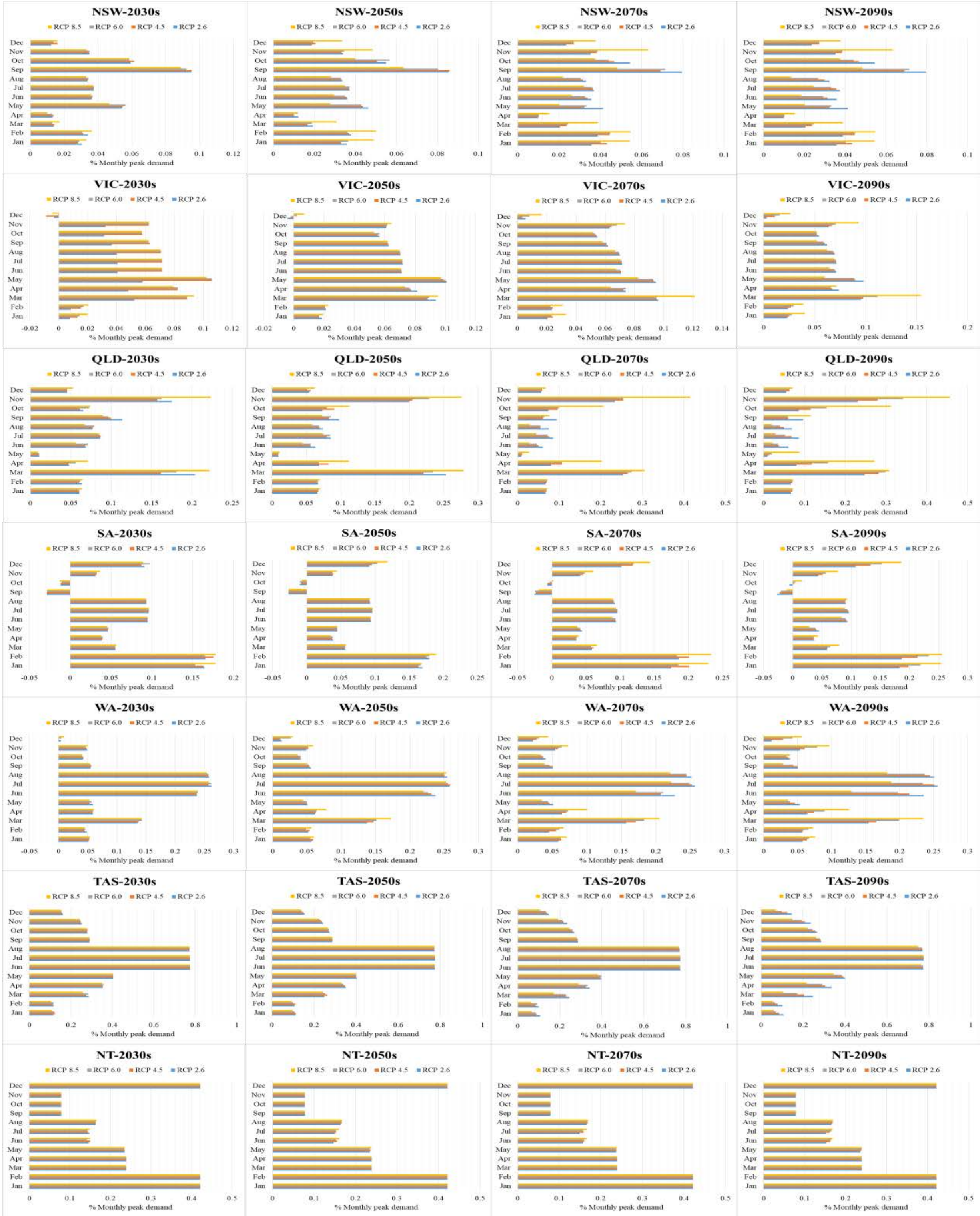

Figure A6.2: Monthly peak demand using the IPCC RCPs in Australia for the 2030s, 2050s, 2070s, and 2090s

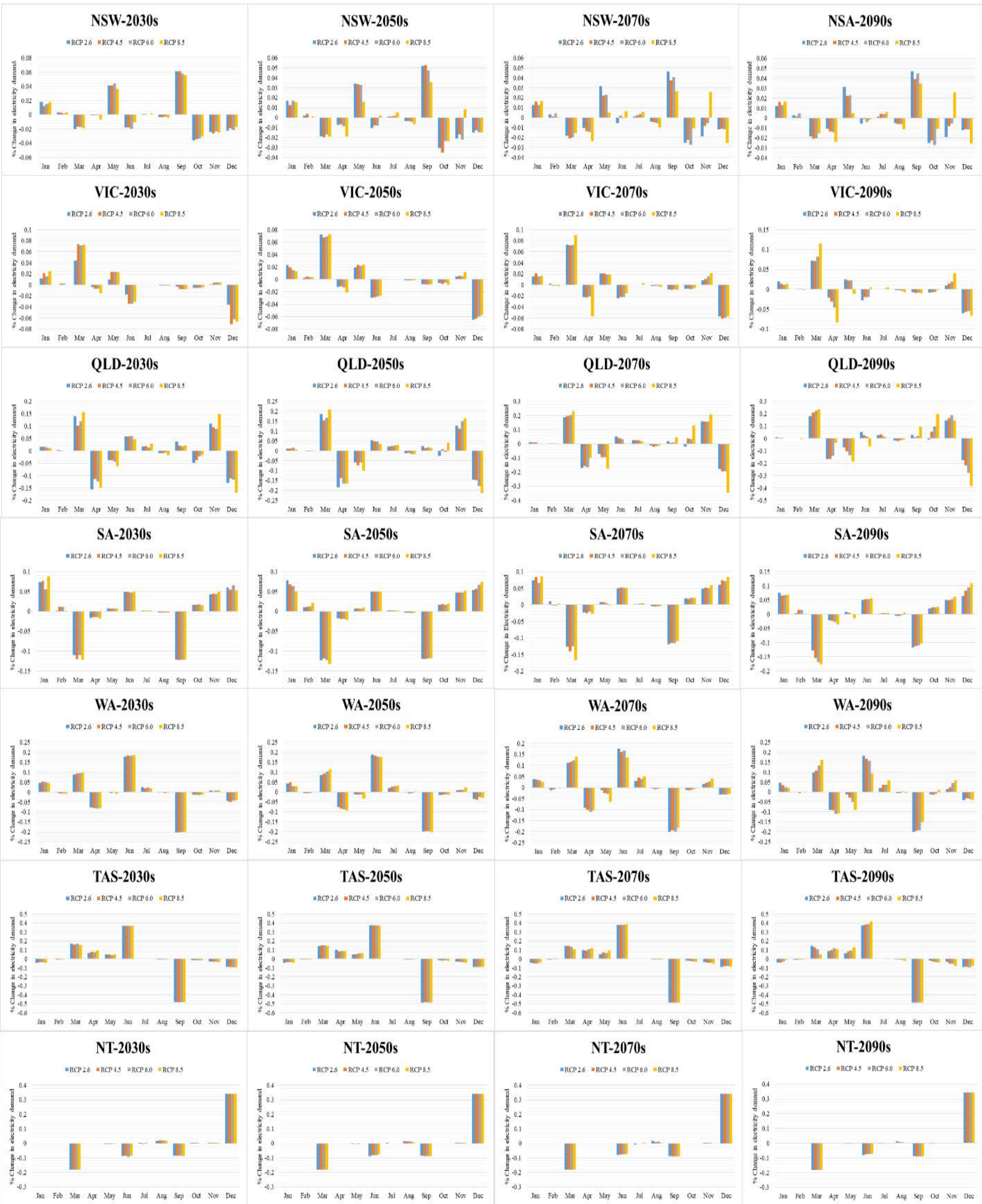

Figure A6.3: Percentage changes in electricity demand using the IPCC RCPs in Australia in the 2030s, 2050s, 2070s, and 2090s